DIRECT TESTIMONY OF

GREGORY M. LANDER

ON BEHALF OF

SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND

SOUTHERN ALLIANCE FOR CLEAN ENERGY

DOCKET NOS. 2017-370-E; 2017-305-E; 2017-207-E

Introduction

Q Can you please state your name and employment?

A My name is Gregory M. Lander. My business address is 83 Pine Street, Suite 101, West 3 Peabody, MA 01960, and my email address is glander@skippingstone.com.

Q On whose behalf are you testifying?

A The South Carolina Coastal Conservation League and the Southern Alliance for Clean Energy.

Q What are your qualifications?

A I am President of Skipping Stone, LLC ("Skipping Stone").

Q. What is your educational and professional background?

A I graduated from Hampshire College in Amherst, Massachusetts, in 1977, with a Bachelor of Arts degree. In 1981, I began my career in the energy business at Citizens Energy Corporation in Boston, Massachusetts ("Citizens Energy"). I became involved in the natural gas business of Citizens Energy in 1983. Between 1983 and 1989, I served as Manager, Vice President, President and Chairman of Citizens Gas Supply Corporation (a subsidiary of Citizens Energy). I started and ran an energy consulting firm, Landmark Associates, from 1989 to 1993, during which time I consulted on numerous pipeline open access matters, a number of Federal Energy Regulatory Commission ("FERC") Order No. 636 rate cases, pipeline certificate cases, fuel supply and gas transportation issues for independent power generation projects, international arbitration cases involving renegotiation of pipeline gas supply contracts, and natural gas market information requirements cases (FERC Order Nos. 587 et seq.). In 1993, I founded TransCapacity LP, a software and natural gas information services company. Since 1994, I have also been a Services Segment board member of the Gas Industry Standards Board ("GISB") and its successor organization, the North American Energy Standards Board ("NAESB"). During the period 1994 to 2002, I served as a Chairman of the Business Practices Subcommittee, the Interpretations Committee, the Triage Committee, and several GISB/NAESB Task Forces. I am currently a Board Member of NAESB and have served continuously in that capacity since 1997. Skipping Stone, Inc. acquired TransCapacity in 1999, and since that time I have headed up Skipping Stone's Energy Logistics practice, where my specialization has been interstate pipeline capacity issues, information, research, pricing, acquisition due diligence and planning. In 2001, Skipping Stone launched CapacityCenter.com, a pipeline capacity information service. In 2004, Skipping Stone was acquired by Commerce Energy Group, a national retail energy services provider. In 2005, I was appointed President of Skipping Stone, which operated as a wholly owned subsidiary of Commerce Energy Group. In 2008, I purchased substantially all of the assets of Skipping Stone and now operate essentially the same business as before the Commerce Energy transaction as Skipping Stone, LLC.

From 1984 to present, I have maintained a deep familiarity with a wide range of pipeline transportation issues, beginning with access to pipeline capacity to make competitive sales, resolution of the pipeline take-or-pay contracting regime, pipeline affiliate marketer concerns, restructuring of the pipelines from merchants to transporters and thereafter, and definitions of what constituted a pipeline capacity "right" for the purposes of formulating the then newly commenced capacity release and capacity rights trading business process. I continue to be involved in nearly all facets of the capacity information and trading business as part of my duties at Skipping Stone. In addition, I have been the lead principal on all 50+ pipeline and storage mergers and acquisitions transactions as well as all pipeline and storage facility expansion projects for which Skipping Stone has been retained by potential purchasers and project sponsors to provide economic due diligence consulting and market analysis.

Q. Have you filed testimony in regulatory proceedings previously?

A I have filed testimony in several proceedings including FERC Docket No. RP04-251-000, which was an El Paso Natural Gas Company ("EPNG") proceeding regarding pathing and segmentation. In FERC Docket No. RP08-426-000, (also an EPNG proceeding), I sponsored answering and supplemental answering testimony. I also filed testimony in FERC Docket No. RP10-1398, the first fully litigated EPNG Rate case in more than three decades. In addition, I have filed testimony in Massachusetts Department of Public Utilities Case Nos. 13-157, 15-34, 15-48, 15-39; Maine Public Utilities Commission Case No. 2014-00071; Virginia Corporation Commission Case No. PUR-2017-00051; Missouri Public Service Case GR-2017-0215; GR-2017-0216; California Public Utilities Commission Cases 17-10-007 and 17-10-008 (Consolidated) Applications of San Diego Gas & Electric (U902M) and Southern California Gas Company (U 338-E) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019; Virginia State Corporation Case No. PUR-2018-00067 *Application of Virginia Electric and Power Company to revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia*; California Public Utilities Commission Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) Regarding Feasibility of Incorporating Advanced Meter Data Into the Core Balancing Process Application 17-10-002; Virginia State Corporation Commission Case No. PUR-2018-00065 *Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq*.; and Federal Regulatory Commission Constellation Mystic Power, LLC Docket No. ER18-1639. Please refer to Exhibit GL-1, which contains a full list of case names and docket numbers as well as my current CV.

Summary

Q Can you provide a summary of your testimony?

A My testimony concerns implications for adverse ratepayer impacts arising in connection with the proposed merger of South Carolina Electric and Gas ("SCE&G") and Dominion Energy ("Dominion") involving the potential for affiliate transactions between Dominion's Atlantic Coast Pipeline ("ACP") and the surviving SCE&G subsidiary of Dominion. In short, if the merger goes through, then SCE&G becomes one more arm in the wide-ranging Dominion conglomerate. When it comes to ratepayer protection, the Commission should be very concerned about Dominion. Given Dominion's track record in Virginia, there is a serious risk that Dominion could justify extending the Atlantic Coast Pipeline into South Carolina using precedent agreements between its affiliated pipeline (namely Atlantic Coast Pipeline, LLC) and its future affiliate SCE&G. Given my analysis of natural gas pipeline capacity already in place in, and available to, South Carolina as well as my familiarity with Dominion's treatment of customers in Virginia, extending the Atlantic Coast Pipeline into South Carolina would be extraordinarily expensive for ratepayers with as yet no justification for that expense. To protect against this, if the Commission approves the proposed merger, it should contemporaneously place substantial guardrails on affiliate transactions to protect ratepayers against self-dealing between Dominion and its affiliates, including SCE&G.

Dominion and South Carolina

Q Why is any of this relevant to this proceeding?

A This docket concerns a merger between Dominion and SCANA. Once that merger closes, SCE&G will become a Dominion subsidiary. This affiliate relationship could expose SCE&G ratepayers to the same abuses of affiliate transactions that will saddle Dominion's Virginia customers with billions of dollars in unnecessary costs over the coming decades. The concern here is that where a utility holding company is a partner in the development of an interstate pipeline (here, Dominion), that holding company will enter into contracts for gas transportation with its subsidiary utilities (here, SCE&G) that expose the subsidiary utility's captive ratepayers to the risk of overpayment. The Commission should be particularly on guard with Dominion and the ACP given statements Dominion has made in the past about bringing the ACP into the state.Test

Q What statements?

A For instance, earlier this year, Dominion CEO Tom Farrell described SCANA as a "natural fit" for Dominion, stating that the "combination can open new expansion opportunities, including the Atlantic Coast Pipeline that is now under development. . . ."[1]

Q You say the additional billions of dollars are unnecessary in Virginia because Virginia doesn't need the ACP. How do you know the same is true for South Carolina?

A My analysis shows that South Carolina has no need for additional interstate natural gas pipeline capacity to bring natural gas to South Carolina.

Q How do you know that?

A I have prepared a detailed report on the subject matter, attached as Exhibit GL-2, that reaches several key conclusions: (1) there is ample pipeline capacity to serve the needs of SCE&G through at least the winter of 2027-2028;[2] (2) it is not currently economical to build the miles of gas distribution line required to access the load in the Pee Dee region. If it were cost-effective to expand local natural gas distribution capacity in the Pee Dee area, SCE&G and/or Dominion's in-state Dominion Carolina Gas Transmission (DCGT)[3] could be expanded to serve this region without any need for additional out-of-state interstate natural gas supply.[4]

Q Does anyone else share your opinion?

A I would note that Transco has intervened in this docket, raising concerns about duplicative pipeline infrastructure and arguing that the proposed merger poses a threat to

---

[1] Meg Kinnard, *Shareholders of Troubled SC Utility Approve Merger Plan* (July 31, 2018, 11:23 AM), https://www.usnews.com/news/best-states/south-carolina/articles/2018-07-31/shareholders-of-troubled-sc-utility-to-vote-on-merger-plan.

[2] *Assessment of South Carolina Natural Gas Pipeline Capacity, A Skipping Stone Report*, August 2018 ("Skipping Stone Report") at 1.

[3] Dominion Carolina Gas Transmission is the former SCANA subsidiary Carolina Gas Transmission bought by Dominion Energy in 2015.

[4] Skipping Stone Report at 1.

Transco's current contracts with SCE&G. It is my belief that those contracts and contracts of others[5] on pre-existing pipelines offer more than adequate gas supply at substantially lower cost than any new greenfield pipeline could, especially an extension of the ACP.

Dominion in Virginia

Q You mentioned your "familiarity" with Dominion in Virginia. Please explain that.

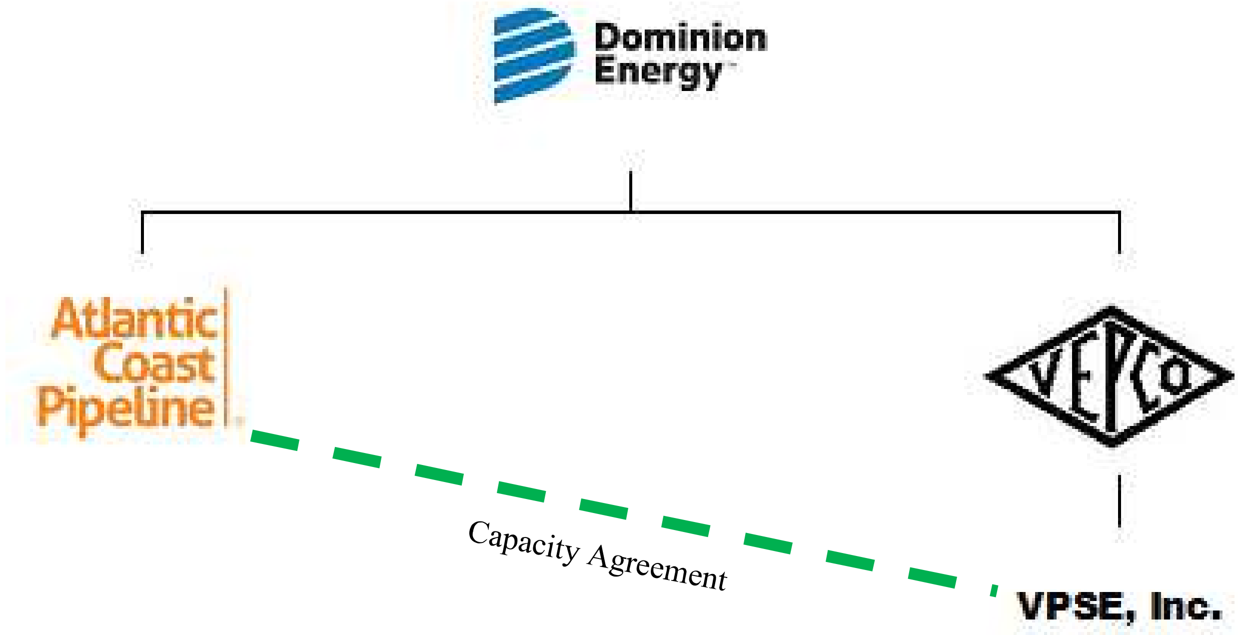
A I have testified in several dockets before the Virginia State Corporation Commission regarding Dominion's methods of procuring natural gas pipeline capacity. My testimony in those dockets has also addressed the affiliate transactions Dominion has used to shift risk and cost of the Atlantic Coast Pipeline onto its captive utility customers in Virginia. I have appended to this testimony the relevant testimonies and attachments from the Virginia dockets.

Q Please explain how that has happened.

A Dominion Energy is the parent company. It wholly owns Virginia Electric and Power Company ("VEPCo"). Dominion is also a member of Atlantic Coast Pipeline, LLC, which is proposing to build the ACP. VEPCo wholly owns a company called VPSE, Inc. ("VPSE"), which has authority to procure natural gas pipeline capacity on VEPCo's behalf. Dominion affiliate VPSE has signed a precedent agreement with Dominion affiliate Atlantic Coast Pipeline, LLC for 300,000 Dth/day. This org chart explains both the legal relationship between the various entities as well as the pipeline capacity agreement between VPSE and Atlantic Coast Pipeline, LLC.

---

[5] Skipping Stone Report at 17.



Q What does the VPSE contract mean for VEPCo customers?

A In Virginia, VEPCo passes the costs of that precedent agreement, as well as other gas contracts, on to its customers via the annual fuel factor proceeding.

My most recent analysis shows the ACP contract will add between $2.5 billion and $3 billion to VEPCo customers' bills,[6] even though VEPCo does not need ACP's capacity at all.[7] In fact, VEPCo has admitted before the Virginia SCC that it never even conducted a study of whether it needed the ACP capacity.[8]

Q Hasn't Dominion claimed that the ACP would save its customers money in Virginia?

---

[6] Testimony of Gregory M. Lander, *Virginia Electric and Power Company - Integrated Resource Plan filing for 2018 pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2018-00065 ("Lander 2018 IRP Testimony") at 3:12-18, attached as Exhibit GL-3.

[7] Lander 2018 IRP Testimony at 49:8-10 ("Company ratepayers will experience no net value from paying for the [Atlantic Coast Pipeline] path connecting Dominion South Point to Transco Zone 5 . . . .").

[8] Dominion Discovery Response to Environmental Respondents' Interrogatories, Sixth Set, Question 20, *Application of Virginia Electric and Power Company in re: Virginia Electric and Power Company's Integrated Resource Plan filing*, Case No. PUR-2017-00051, attached as Exhibit GL-4.

A It has, but those claims ignore the costs of paying for the pipeline; and – once those costs are considered – those claims are completely wrong.

Q Why are they wrong?

A In 2014, Dominion commissioned a report from ICF to calculate how much money the ACP would save Virginia customers (the "ICF Report").[9]

Q How did that assumption drive the report's results?

A The ICF Report estimated that the ACP would produce $243 million in net energy savings in Virginia.[10]

Q Do you agree with those results?

A No. The ACP will not produce any net annual energy savings for Virginia.

Q Why not?

A ICF made two fatal, fundamental errors in its assumptions that made the analysis flawed.

Q What errors led to this flaw?

A The ACP will access gas in an area of the Utica/Marcellus region (*i.e.*, the Dominion South Point pricing hub) that, when ACP was proposed had, and to a lesser extent today, has less pipeline takeaway capacity than production volumes, and consequently the Dominion South Point gas was, and to a lesser extent, is currently priced (i.e., sold/sells) below market. One fatal flaw was that the ICF Report did not factor in that other pipeline projects' impacts on price (*i.e.*, increasing takeaway capacity from the Dominion South Point region to other destinations) would relieve downward price pressure. The second fatal error was that ICF assumed that the gas prices at

---

[9] *See* "The Economic Impacts of the Atlantic Coast Pipeline, Prepared for Dominion Transmission, Inc.," attached as Exhibit GL-5.
[10] ICF Report at 5.

Dominion South Point would remain below market even after the combined effect of these other projects and completing the ACP.[11] Together, these errors led to a fatal flaw.

Q Is there evidence, other than this flawed claim, that the ACP would produce ratepayer savings?

A Virtually none, because not even Dominion believes ACP gas will actually sell below market after building the ACP. Through discovery in the 2017 and 2018 VEPCo Integrated Resource Plan dockets in Virginia, we obtained VEPCo's own internal gas commodity price forecasts. Not surprisingly, VEPCo's internal analysis confirmed that they expect gas at Dominion South Point to trade more or less at parity with the prevailing market prices; and, not a dollar or more below market prices after completing the ACP. In fact, recent articles published by respected observers note that this below-market differential in prices is already eroding[12] due to the completion of projects unrelated to ACP.

Q So if Dominion expects ACP gas to sell at market, what does that do for VEPCo ratepayers?

A As discussed at length in my testimony in Dominion's 2018 IRP in Virginia, the ACP will ***increase*** customer costs in Virginia by between $2.5 billion and $3 billion.[13]

Q You claim VEPCo doesn't need the ACP. Then why is Dominion building it?

A The traditional regulated utility business model depends on earning a regulated rate of return on capital projects. The more capital projects a utility can build and earn its regulated return on, the higher its total earnings. In the past, those capital projects took the form of power plants. Today, however, with electricity demand flat or declining

[11] ICF Report at 10.
[12] *See* RBN Energy LLC; published September 12, 2018; https://rbnenergy.com/.
[13] Lander 2018 IRP Testimony at 49.

across the country, utilities are turning to different capital projects to increase their rate base and associated earnings, including building and owning interstate gas pipelines.

Q Is Atlantic Coast Pipeline, LLC a regulated utility?

A It is not regulated by any state public service commission, but VEPCo is, and Dominion owns both VEPCo and Atlantic Coast Pipeline, LLC. As such, Dominion has exploited the affiliate relationship between VEPCo and Atlantic Coast Pipeline, LLC to shift the risk of the project from Atlantic Coast Pipeline, LLC shareholders (owners) to VEPCo's captive customers. That's why public utility commissions must pay extremely close attention to natural gas pipeline capacity contracts between a state regulated utility and its non-state regulated affiliates. The contracts between the pipeline and the state regulated utility allow the parent holding company, in this case Dominion, to earn a FERC-approved 14% rate of return on a capital project that utility ratepayers do not need and that will only increase utility ratepayer costs.

Conclusions

Q So what are your conclusions?

A My conclusions are as these:

i) Greenfield interstate natural gas pipelines are incredibly expensive and – in those instances when they are underwritten by contracts with local utilities affiliated with the pipeline – needless, given the surplus of operable, lower cost pipelines already in the ground and already serving those local utilities.

ii) Those pipelines can radically inflate ratepayer costs with no attendant benefit.

iii) SCE&G has no need for additional capacity on an interstate natural gas pipeline to bring gas to South Carolina, nor does the Pee Dee region need such a pipeline.

iv) The Dominion merger with SCANA creates a significant risk to SCE&G customers that Dominion will treat them as it has treated its customers in Virginia – namely to use them as cash machines to fund a needless multi-billion dollar undertaking that provides no ratepayer benefit.

Q What can the Commission do to protect ratepayers?

A If the Commission approves the merger, it should only do so by imposing a requirement that SCE&G first engage in a "needs analysis" in a public proceeding under the auspices of this Commission where demand is identified; including and most importantly, where details of the seasonal and load factor characteristics of that demand are established.

Then, second undertake a comparative cost analysis of meeting that identified demand with extension or expansion of SCE&G services and facilities (including cost-effective demand side management and energy efficiency, and utilization of its and others' available peaking facilities. In this public proceeding, interested parties should have the opportunity to evaluate and comment on the "needs" and "comparative cost analysis," and the Commission should review the analysis and ensure they are accurate and that intervenor criticisms are taken into account where appropriate.

Next, should the character of the identified demand cost-effectively warrant additional supplies be brought to SCE&G and/or DCGT for SCE&G, then require a public, transparent "delivered gas" and/or "pipeline capacity" procurement process, possibly involving a competent, third-party, evaluator/reviewer's report to this Commission to ensure that the utility does not unreasonably commit its customers to billions of dollars in unjustified costs. Central to this "delivered gas" and/or "pipeline capacity" procurement process would be solicitation of parties (with capacity on Transco and other pipelines that are able to deliver to DCGT for SCE&G), firm delivered gas proposals to meet the identified demand. The reason for inclusion of this "delivered gas" portion of the solicitation is that there are parties with capacity, especially on Transco which can deliver to DCGT for SCE&G, which parties are not utilities with native load needing to be served and thus have supplies through existing capacity that could be contractually committed to the particular identified demand needs of SCE&G.

Finally, the Commission should condition its merger approval on getting a binding commitment from DCGT that it will undertake SCE&G-requested expansions and/or extensions of the DCGT system to enable SCE&G to undertake fulfillment of the results of the SCE&G procurement process. In addition and as a general requirement, this Commission should also impose carefully crafted regulatory conditions on any merger that ensure vigorous ongoing oversight of affiliate transactions. Such ongoing oversight could involve the requirement that affiliate transactions (either individually or in aggregate exceeding some Commission defined monetary and/or duration threshold) be subject to a public RFP and bidding process.

Q Does this conclude your testimony?

A Yes.

Schedule SCCF-01: Expert Testimony of Gregory M. Lander

Name of Case	Jurisdiction	Docket Number	Date
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP04-251-000	May 3, 2004 (Testimony)
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP08-426-000	May 19, 2009 (Answering Testimony) June 2, 2010 (Supplemental Answering Testimony)
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP10-1398-000	June 28, 2011 (Answering Testimony) March 4, 2014 (Answering Testimony)
Petition of Boston Gas Company and Colonial Gas Company, each d/b/a National Grid for Approval by the Department of Public Utilities for a Firm Transportation Contract with Algonquin Gas Transmission Company	Massachusetts Department of Public Utilities	13-157	December 12, 2013 (Direct Testimony)
Petition of Boston Gas Company d/b/a National Grid for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate	Massachusetts Department of Public Utilities	15-34	June 5, 2015 (Direct Testimony)

pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project			
Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project	Massachusetts Department of Public Utilities	15-39	June 5, 2015 (Direct Testimony)
Petition of The Berkshire Gas Company for Approval of a Precedent Agreement with Tennessee Gas Pipeline Company, LLC, pursuant to G.L. c. 164, § 94A	Massachusetts Department of Public Utilities	15-48	June 5, 2015 (Direct Testimony)
Investigation of Parameters for Exercising Authority Pursuant to Maine Energy Cost Reduction Act, 35-A M.R.S.A. Section 1901	Maine Public Utilities Commission	2014-00071	July 11, 2014 (Direct Testimony)
Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 *et seq*.	Virginia Corporation Commission	PUR-2017-00051	August 11, 2017 (Direct Testimony)
In the Matter of the Laclede Gas Company's Request to Increase Its Revenues for Gas	Missouri Public Service Commission	**File No. GR-2017-0215**	September 8, 2017 (Direct Testimony)

Service In the Matter of the Laclede Gas Company d/b/a Missouri Gas Energy's Request to Increase Its Revenues for Gas Service		**File No. GR-2017-0216**	Consolidated and November 21, 2017 (Surrebuttal Testimony) Consolidated
Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019. Application of Southern California Gas Company (U904G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2019.	California Public Utilities Commission	Application 17-10-007 Application 17-10-008	Consolidated Direct Testimony May 14, 2018 Rebuttal Testimony June 8, 2018
Application of Virginia Electric and Power Company to revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia	Virginia State Corporation Commission	PUR-2018-00067	Direct Testimony June 14, 2018
Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) Regarding Feasibility of Incorporating Advanced Meter Data Into the Core Balancing Process	California Public Utilities Commission	Application 17-10-002	July 2, 2018 (Direct Testimony) September 7, 2018 (Supplemental Direct Testimony)
Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 *et seq*.	Virginia Corporation Commission	PUR-2018-00065	August 13, 2018 (Direct Testimony)
Constellation Mystic Power, LLC	Federal Energy Regulatory Commission	Docket No. ER18-1639	August 23, 2018 (Prepared Answering

			Testimony September 4, 2018 (Prepared Cross-Answering Testimony)

Greg Lander, President
Skipping Stone LLC

Professional Summary:

As President of Skipping Stone Inc., Greg Lander is responsible for Strategic Consulting in the mergers and acquisition arena with numerous clients within the energy industry. Generally recognized in the energy industry as an expert, he has advised and/or given testimony at numerous Federal Energy Regulatory Commission (FERC), State, arbitration, and legal proceedings on behalf of clients and has advised as well as initiated standards formation before the Gas Industry Standards Board (GISB) (predecessor to the North American Energy Standards Board (NAESB)). As Founder, President, and Chief Technology Officer of TransCapacity Limited Partnership, he was responsible for conceiving, planning, managing, and designing Transaction Coordination Systems utilizing Electronic Data Interchange (EDI) between trading partners. As a founding member of GISB, he assisted in establishing protocols and standards within the Business Practices, Interpretations and Triage Subcommittees.

Professional Accomplishments:

- Handled all Due Diligence for purchaser (Loews Corp) in acquisitions of two interstate pipelines, one natural gas storage complex, and ethylene distribution and transmission systems (Texas Gas Transmission, Gulf South Pipeline, Petal Storage, Petrologistics, and Chevron Ethylene Pipeline) most in excess of $1 Billion. Developed purchaser's business case model, including rate/revenue models, forward contract renewal models, export basis modeling and revenue models, and operating cost and capex models. Coordinated Engineering and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.
- Assisted major electric retailer in 9 states with business case development for entry into North Eastern U.S. Commercial &Industrial natural gas marketing business. Identified market share of incumbents; retail registration process, billing processes; utility data exchange rules and procedures and developed estimates of addressable market by utility.
- Handled all economic Due Diligence for purchaser of large minority stake in Southern Star Gas Pipeline. Developed purchaser's business case model, including rate/revenue models and forward contract renewal models, assessed potential competitive by-pass of asset located in "pipeline alley", developed revenue models and operating cost and capex models. Coordinated Engineering, Pipeline Integrity, and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.
- Developed post-acquisition integration plans for inter-operability and alterations to system operations to take advantage of opportunities presented by

synergistic facilities' locations and functions and complimentary contractual requirements. Implementation of plan resulted in fundamental changes to systems operations and improvement in systems, net revenues, capacity capabilities, and facilities utilization.

- Handled all economic analysis, modeling, and systems capability due diligence for potential purchaser in several preliminary or completed yet un-consummated pre-transaction investigations involving Panhandle Eastern, Northern Border, Bear Paw, Florida Gas, Transwestern, Great Lakes, Guardian, Midwestern, Viking, Southern Star, Columbia Gas, Midla, Targa (No. Texas), Ozark, ANR, Falcon Gas Storage, Tres Palacios, Rockies Express, Norse Pipelines, Southern Pines, Leaf River, LDH (Mont Belvieu), Kinder Morgan Interstate, Trailblazer, Rockies Express and South Carolina Gas Transmission.
- Post Texas Gas Transmission and Gulf South Pipe Line acquisitions, assisted with all investigations involving assessments and proposals for realizing potential synergies with/from asset portfolio; rate case strategy development and alternate case development; and strategies around contract renewal challenges.
- Headed up due diligence team in acquisition of multi-state retail (residential) natural gas and electric book by Commerce Energy.
- Headed up due diligence team in acquisition of multi-state retail (C&I) natural gas book by Commerce Energy.
- Served as lead consultant for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in several major FERC Rate Cases, service restructuring, and capacity allocation proceedings involving a major Southwestern U.S. Pipeline.
- Expert witness in numerous gas and electric utility rate cases; integrated resource plans; litigated service offerings and cost approval and allocation proceedings for public interest clients. Controversies, often involving hundreds of millions to billions of dollars over cases' time horizons, are common.
- Served as lead consultant and expert witness for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in major FERC rate case under litigation involving decades-long disputes over service levels, cost allocation, and rate levels.
- Served as lead consultant for consortium of end-users and municipalities in major FERC rate case involving implementation of proposed rate design, cost allocation, and rate level changes.
- Developed and critiqued Rate Case Models for several pipeline proceedings and proposed proceedings (as consultant variously to both pipeline and shippers). Activities included modeling (and critiquing) new services' rates, costs, and revenues; responsibilities included development of various alternative cost allocation/rate designs and related service delivery scenarios.

- Handled all market assessment, forward basis research, and transportation competition modeling for several proposed major pipelines and laterals, including two $1 Billion+ Greenfields projects that went into construction and operation providing new outlets for growing southwestern shale production. (Gulf Crossing and Fayetteville Lateral).
- Assessed supply and demand balance for Southwestern US (OK, TX, Gulf Coast and LA) including assessment of future demand and supply displacement associated with West Texas wind power development and its likely impact on pipeline export capacity from region.
- Assessed supply and demand balance for Northeast to Gulf Coast capacity additions including assessment of Gulf Coast demand and export growth and its likely impact on forward basis.
- Assessed start-up gas supply needs for Appalachian coal fired power plant, resulting in installation of on-site LNG storage and gasification to address lack of enough firm pipeline capacity to meet need.
- Assessed installed and projected wind-turbine capacity in ERCOT and its eventual impact on Texas electric market as wind power output approaches minimum ERCOT load levels.
- Designed and developed EDI based data collection system, data warehouse and web-based delivery system (www.capacitycenter.com) for delivering capacity data collected from pipelines to shippers, marketers, traders, and others interested in capacity information to support business operations and risk-management requirements.
- Designed pipeline capacity release deal integrating settlement system for firm users, including design and development for information services delivery on a transaction fee basis.
- Assisted client in developing proposals to increase pipeline capacity responsiveness and proposed market fixes that would create price signals around sub-day non-ratable flows, including rate proposals, sub-day capacity release markets, and measures to address advance reservation of capacity for electric generation fuel to meet sub-day generation demands.
- Developed "universal capacity contract" data model for storage of all interstate capacity contract transactions from all 60 major interstates in single database.
- Led design effort culminating in FERC-mandated datasets defining pipeline capacity rights, (including receipt capacity, mainline capacity, delivery capacity, segmentation rights, in and out of path capacity rights), Operationally Available Capacity, Index of Customers, and Transactional Capacity Reports (through GISB).
- Assembled consortium of utilities to investigate and develop large high-deliverability salt storage cavern in desert southwest (Desert Crossing). As LLC's Acting Manager, was responsible for developing business case and

economic models; handling all partner issues and reporting; coordinating all field engineering, facilities design, planning and siting; and managing all environmental, legal, engineering and regulatory activities. Wrote FERC Tariff. Brought project to NEPA Pre-Filing Stage and conducted non-binding Open Season, as well as assisted with prospective shipper negotiations. Project cancelled due to 2001 "California Energy Crisis" and contemporaneous Enron and energy trading sector implosions.

- Designed comprehensive retail energy transaction and customer acquisition data model, process flow, and transaction repository for web-based customer acquisition and customer enrollment intermediary.
- Experienced in negotiation and drafting (from both seller side and buyer side) of firm supply, firm transportation, firm storage, and power supply and capacity agreements for numerous entities including project financed IPPs and for new greenfields pipeline and expansion of storage system.
- Conducted interstate pipeline capacity utilization analysis for New England following winter of 2013/2014 price fly-up.
- Conducted PJM East interstate gas pipeline capacity utilization and comparative analysis between pipelines with standard NAESB nominating cycles versus those with near hourly scheduling practices.
- Conducted requirements analysis for several firms pursuing software selection of energy transaction systems.
- Instrumental in the formation of the GISB. Member of industry team that lead the development of the proposal for and bylaw changes related to the formation of NAESB.
- Provided support to numerous clients and clients' attorneys in disputes involving capacity contracts, capacity rights allocations, tariffs, rate cases, and supply contract proceedings as both up-front and behind the scenes expert.

Associations and Affiliations:

Longest serving Member of Board of Directors for NAESB and prior to that GISB - 22 years.

GISB Committees: Former Chairman, Business Practices Subcommittee – drafted approximately 450+ initial industry standards that are now codified FERC regulations (Order 567); Former Chairman, Interpretations Subcommittee – drafted and led adoption process for first 50+ standards interpretations; Former Chairman, Triage Subcommittee; Title Transfer Tracking Task Force; Order 637 GISB Action Subcommittee; and industry Common Codes Subcommittee. Currently member of NAESB Wholesale Gas Quadrant Executive Committee and of NAESB Parliamentary Committee.

Past and Affiliations and Associated Accomplishments:

1981-1989: One of five initial employees of Citizens Energy Corporation, Boston Mass. Responsible for starting and growing Citizens Gas Supply, one of the first independent gas marketers of the early 1980's, into $200MM+ annual operation. Successfully lobbied for pipeline Open Access (Orders 436 and 636), introduction of pipeline Affiliated Marketer rules of conduct (Order 497), and Open Access to pipeline operational information (Order 563).

1989-1993: Independent Consultant - Natural Gas Projects, Pipeline Rate Cases, Project Financed Contract negotiations, and Independent Power markets

1993 – 1999: Founder and President, TransCapacity Service Corp – Software products and services related to pipeline capacity trading, nomination, and contracting. Raised $17 MM from industry player to establish TransCapacity. Successfully lobbied for Pipeline restructuring and formation of capacity release market (Order 636). Sold to Skipping Stone.

1999 – 2004: Principal and Partner, Skipping Stone – Energy market consultants

2004 – 2008: President of Skipping Stone following purchase of Skipping Stone by Commerce Energy, Inc.

2008: Repurchased Skipping Stone from Commerce Energy, Reformulated Skipping Stone as LLC with Peter Weigand

2008 to Present: President and Partner, Skipping Stone. In addition to handling book of clients, responsible for all Banking, Accounting, Operations, Risk Management and contract matters for Skipping Stone.

Education:

1977: Hampshire College, Amherst, MA; Bachelor of Arts

Publication:

2013: Synchronizing Gas & Power Markets - Solutions White Paper

Assessment of South Carolina Natural Gas Pipeline Capacity

A Skipping Stone Report

August 2018

Prepared for the Southern Environmental Law Center

About Skipping Stone
Skipping Stone is a consulting and technology services firm that helps natural gas and electricity utilities, market participants, and solution providing clients globally to navigate market changes, capitalize on opportunities, and manage business risks. The firm provides a wide array of services from innovation through strategy development, market research and assessment to implementation of business plans and technologies. Skipping Stone's model of deploying energy industry executives has delivered measurable bottom-line results for more than 270 clients globally.

Skipping Stone operates Capacity Center, a proprietary technology platform and data center that is the only all-in-one Capacity Release and Operational Notice information source synced with the Interstate pipeline system. Our database not only collects the data as it occurs, it is a storehouse of historical Capacity Release transactions since 1994. We also track shipper entity status and the pipeline receipt and/or delivery points, flows and capacity. Our analysts and consultants have years of experience working in natural gas markets. Capacity Center has worked with over a hundred clients on a wide variety of natural gas market and pipeline related reports and projects.

Headquartered in Boston, the firm has offices in Atlanta, Houston, Los Angeles, Tokyo and London. For more information, visit www.SkippingStone.com

About SELC
For more than 30 years, the Southern Environmental Law Center has used the power of the law to champion the environment of the Southeast. With more than 80 attorneys and nine offices across the region, SELC is widely recognized as the Southeast's foremost environmental organization and regional leader. SELC works on a full range of environmental issues to protect our natural resources and the health and well-being of all the people in our region. www.SouthernEnvironment.org

Warranties and Representations. Skipping Stone endeavors to provide information and projections consistent with standard practices in a professional manner. SKIPPING STONE MAKES NO WARRANTIES HOWEVER, EXPRESS OR IMPLIED (INCLUDING WITHOUT LIMITATION ANY WARRANTIES OR MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), AS TO THIS MATERIAL. Specifically, but without limitation, Skipping Stone makes no warranty or guarantee regarding the accuracy of any forecasts, estimates or analyses, or that such work products will be accepted by any legal or regulatory body.

Waivers. Those viewing this Material hereby waive any claim at any time, whether now or in the future, against Skipping Stone, its officers, directors, employees or agents arising out of or in connection with this Material. In no event whatsoever shall Skipping Stone, its officers, directors, employees, or agents be liable to those viewing this Material.

Table of Contents

Executive Summary

Skipping Stone was retained by the Southern Environmental Law Center to evaluate the current state of natural gas pipeline capacity in South Carolina, assessing: 1) whether additional natural gas capacity is necessary to meet projected electric demand from South Carolina Gas & Electric Company (SCE&G) customers following the abandonment of two nuclear generating units at V.C. Summer station that were expected to come online in 2020; and 2) anecdotal claims that commercial and industrial growth in the Pee Dee region of the state has been stymied by insufficient interstate or within-state pipeline capacity.

Due to recent developments regarding pipeline capacity within and serving South Carolina, Skipping Stone concludes that there is ample pipeline capacity to serve the needs of SCE&G through at least the winter of 2027-2028. There is sufficient interstate pipeline capacity available on Dominion Carolina Gas Transmission (DCGT)—the pipeline serving the vast majority of SCE&G's gas-fired electric generation and gas distribution[1]—to meet SCE&G's forecasted needs. While there is no additional (year-round) capacity on interstate pipeline Southern Natural Gas (SONAT) to feed DCGT, interstate pipeline Transcontinental Gas Pipe Line (Transco) has several billion cubic feet per day (Bcfd) of capacity. This Transco capacity is well in excess of aggregate DCGT demand levels. As will be discussed in detail below, the "path capacity"[2] passing through South Carolina (whether from south to north or from north to south) is often held by entities that do not have a customer base in need of additional natural gas to meet electricity demands, and as a result sell their gas in the competitive market at locations all along the Transco pipeline.

Skipping Stone also concludes that to the extent the Pee Dee region in eastern and northeastern South Carolina may be currently un- or underserviced by natural gas, this situation is not a result of any interstate natural gas supply shortage. Instead, sparse population density and the high penetration of electric heating have contributed to the limited natural gas distribution infrastructure. It is not currently economical to build the miles of gas distribution line required to access the load in this region. If it were cost-effective to expand local natural gas distribution capacity in the Pee Dee area, SCE&G and/or DCGT could be expanded to serve this region without any need for additional out-of-state interstate natural gas supply.

This analysis is especially timely given media reports that the developers of the Atlantic Coast Pipeline (ACP) have expressed a desire to extend the pipeline into South Carolina, claiming they

[1] With the exception of one gas-fired generator in Aiken County, all of SCE&G's gas-fired generation and gas distribution for residential and commercial customers is served by DCGT.

[2] Path capacity is the capacity under contract to shippers from the shippers' receipt point(s) to their delivery point(s). Under federal rules governing pipelines, a shipper may pick-up (i.e., receive); and drop-off (i.e., deliver) gas a multiple locations along the "path" between their primary receipt and primary delivery locations a process referred to as segmentation, provided they do not overlap their capacity usage along their path such that they exceed their total path capacity.

"could bring in almost a billion cubic feet (28 million cubic meters) a day" into the state.[3] The ACP is a proposed new $5 billion – $6.5 billion interstate gas pipeline that would transport gas extracted from the Marcellus shale into the Southeast, including Virginia and North Carolina. The ACP is being developed by Atlantic Coast Pipeline, LLC (Atlantic)—a joint venture of Dominion Energy, Duke Energy and Southern Company—which asserts that the pipeline is needed to meet demand for natural gas to generate electricity and to supply natural gas distribution utilities in the Southeast. Current plans have the ACP dead ending in Lumberton, North Carolina, 12 miles from the South Carolina border. Dominion Energy is currently in the process of acquiring SCANA, the parent company of SCE&G, which owns a network of distribution pipelines across South Carolina. Earlier this year, Dominion Chief Executive Tom Farrell described SCANA as a "natural fit" for Dominion, stating that the "combination can open new expansion opportunities, including the Atlantic Coast Pipeline that is now under development. . . ."[4]

Skipping Stone's analysis demonstrates that the ACP is not needed to serve forecasted demand in SCE&G territory or to supply gas in the Pee Dee region of the state.

Additional Interstate Pipeline Capacity Is Not Necessary to Meet SCE&G's Forecasted Demand

All natural gas consumed in South Carolina comes into the state from interstate pipelines or as liquefied natural gas delivered to the Elba Island, Georgia facility of Southern LNG (SLNG, a.k.a. the Elba Island LNG facility).[5] There are four interstate natural gas pipelines that deliver natural gas from out-of-state sources: Dominion Carolina Gas Transmission (DCGT), Elba Express Company (EEC),[6] Southern Natural Gas (SONAT),[7] and Transcontinental Pipeline (Transco).[8] DCGT owns and operates the interstate pipeline system with the widest geographic coverage in South Carolina; DCGT's system delivers natural gas to SCE&G, municipal gas distributors, government entities, as well as direct connected power plants and industrial facilities. Most of

[3] Sarah Rankin, *Disputed East Coast Pipeline Likely to Expand* (Sept. 29, 2017, 10:47 AM), https://www.usnews.com/news/business/articles/2017-09-29/apnewsbreak-disputed-east-coast-pipeline-likely-to-expand.

[4] Meg Kinnard, *Shareholders of Troubled SC Utility Approve Merger Plan* (July 31, 2018, 11:23 AM), https://www.usnews.com/news/best-states/south-carolina/articles/2018-07-31/shareholders-of-troubled-sc-utility-to-vote-on-merger-plan

[5] LNG is liquefied natural gas. LNG is chilled natural gas where natural gas volume is reduced 1/600th of its volume in a gaseous state. SLNG is owned in part and operated by Kinder Morgan.

[6] Elba Express Company is an interstate pipeline that is owned and operated by Kinder Morgan. It runs between the Elba Island LNG Terminal operated by SLNG and Transco at the Georgia – South Carolina border.

[7] SONAT is owned in part and operated by Kinder Morgan.

[8] Transco is owned and operated by Williams.

DCGT's facilities are within South Carolina,[9] and served by other interstate pipelines (Transco, SONAT, and EEC) or SLNG[10] and the SCE&G-owned-and-operated liquid natural gas (LNG) facilities referred to as the Bushy Park and Salley facilities.

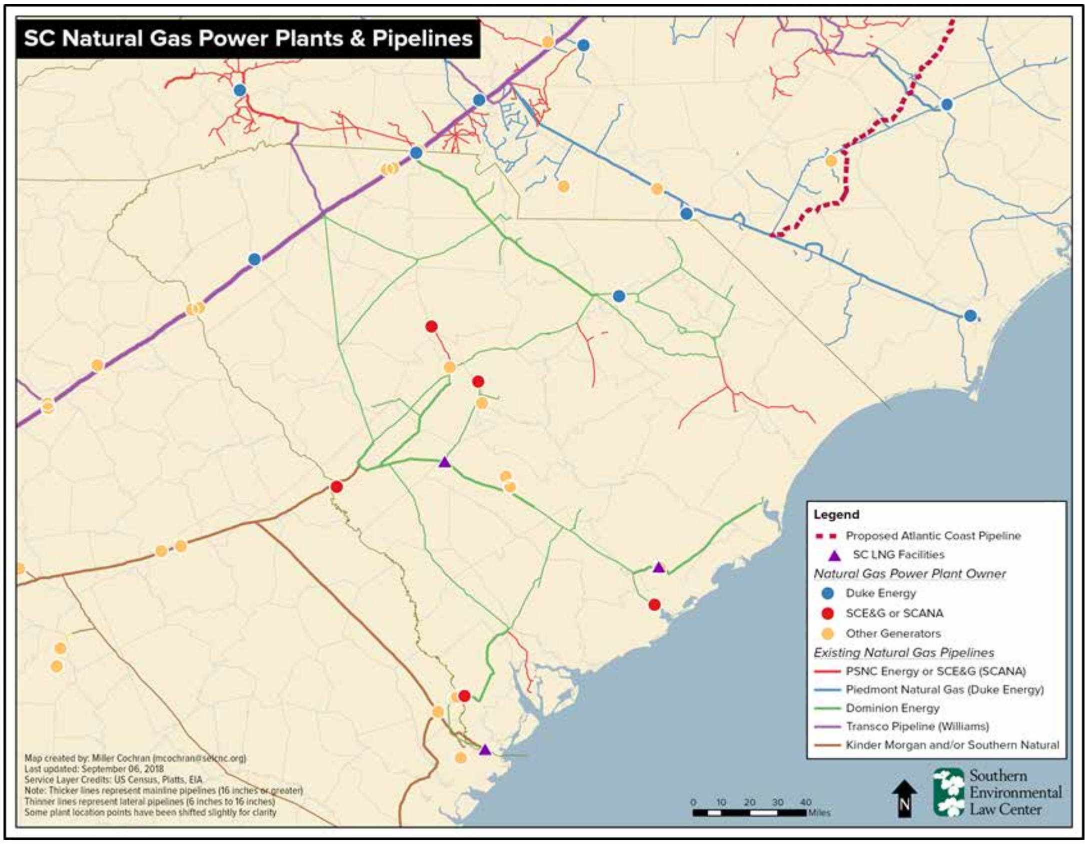


Figure 1: South Carolina natural gas pipelines

In this section, Skipping Stone explains its analysis of scheduled flow data and firm contracted capacity data[11] for DCGT, SONAT, Transco, SLNG, and Elba Express Company, as well as of peak and annual load information for SCE&G's electric generation and gas distribution operations.[12] Skipping Stone set out to determine whether existing natural gas capacity is

---

[9] DCGT extends a short distance into Georgia where it interconnects with the EEC and SLNG.

[10] The SLNG facilities associated with the Elba Island LNG Terminal are considered federally-regulated interstate facilities.

[11] This data is publicly available for pipelines and storage companies that are regulated by the Federal Energy Regulatory Commission. The data can be obtained from the companies' Informational Postings, and from automated, computer to computer electronic data interchange.

[12] SCE&G's 2017 Integrated Resource Plan (covering SCE&G's electric side) estimates future peak and annual loads. SCE&G's 2017 Purchased Gas Adjustment filings with the South Carolina Public Service Commission (covering SCE&G's gas distribution side) provides recent historic loads and the resources it utilizes to meet those loads.

sufficient to meet projected SCE&G electric demand. First, Skipping Stone considered the pipeline capacity available on DCGT, since that pipeline serves the vast majority of SCE&G's gas-fired electric generation and gas distribution.[13] Second, Skipping Stone considered the pipeline capacity available on the interstate pipelines and other facilities that feed into DCGT.

DCGT Capacity is Sufficient to Meet SCE&G's Forecasted Needs

As of January 1, 2018, DCGT had 819,678 dekatherms per day (Dthd) of contracted firm delivery capacity (see Appendix A), up from 611,657 Dthd of contracted capacity in November 2006. Over the 2006 to 2016 period, DCGT grew its capacity primarily by increasing compression rather than by laying new pipe.[14] An additional 80,000 Dthd of capacity was added when the Charleston expansion came fully into service in March 2018; bringing the total contracted DCGT capacity to about 900,000 Dthd (0.90 Billion cubic feet per day (Bcfd)).

To determine whether DCGT has excess capacity, Skipping Stone plotted total daily deliveries to all delivery locations of DCGT between November 1, 2016 and January 21, 2018 against January 1, 2018 firm DCGT contracted delivery capacity, based on DCGT scheduled flow data (DCGT's daily deliveries to all of its locations).

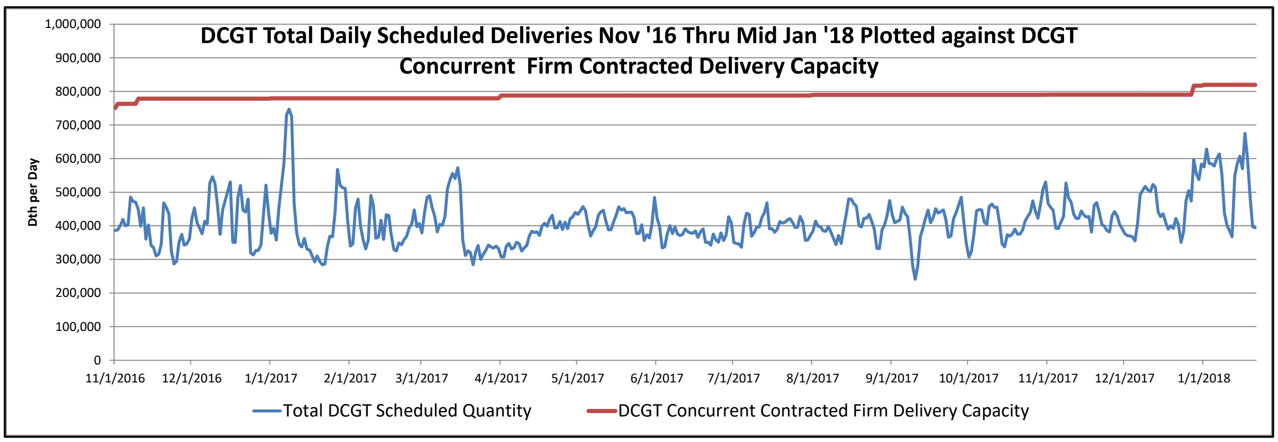


Figure 2: DCGT total daily scheduled deliveries November 2016 through mid-January 2018 plotted against DCGT concurrent firm contracted delivery capacity

Figure 2, above, shows that DCGT has excess capacity that is not generally being utilized. While in January 2017 DCGT approached delivery of an amount of gas nearly equivalent to its contracted firm obligation, DCGT generally only delivers around 50% of maximum contracted

---

[13] With the exception of one gas-fired generator in Aiken County, all of SCE&G's gas-fired generation and gas distribution for residential and commercial customers is served by DCGT.

[14] Between pipe and compression, pipe is the relatively more expensive way to increase capacity until the system can no longer increase capacity by means of compression, (i.e., the system is "fully powered-up"). Given that the Charleston Project involved installation of pipe and compression, it is likely that prior to this project DCGT was fully powered-up with respect to its then-existing facilities.

capacity. Skipping Stone also plotted total DCGT deliveries to all SCE&G locations, including utility-owned power plants and the Columbia Energy Center, as shown in Figure 3.

Figure 3 shows that SCE&G is the primary recipient of gas deliveries from DCGT.

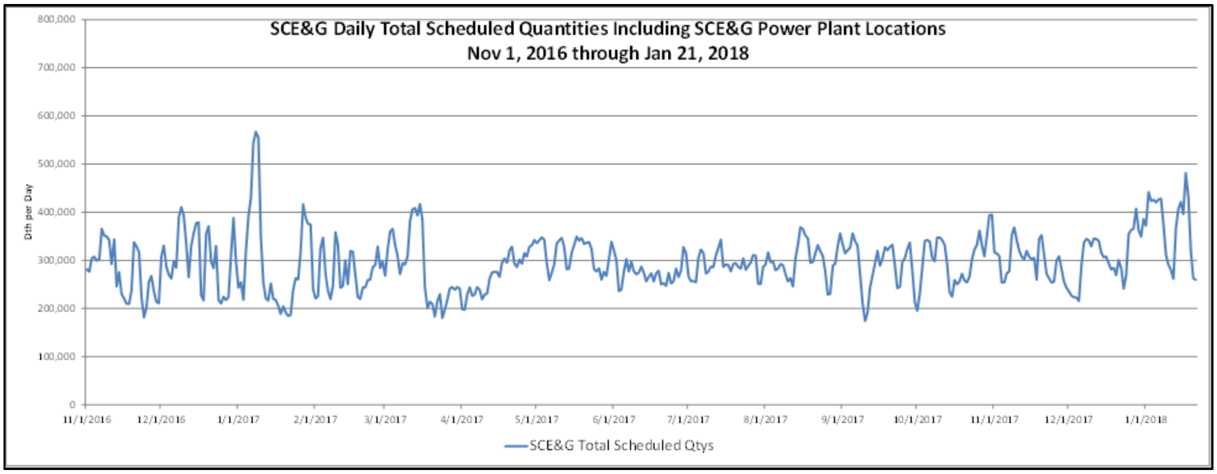


Figure 3: SCE&G daily total scheduled quantity including SCE&G power plants plus Columbia Energy Center deliveries, November 1, 2016 through January 21, 2018

The scale used in Figure 3 approximates the total firm contracted delivery capacity of DCGT at the end of 2017.[15]

In Figure 4 below, Skipping Stone plotted the SCE&G scheduled quantity data for November 2016 through October 2017 used in Figure 3 (the flowing gas and contracted firm delivery capacity SCE&G obtained from interstate pipelines) as a load duration curve. The load duration curve displays scheduled delivery data from highest quantities to lowest over the gas year.[16] Load duration curves indicate the load factor of a system, and help illustrate the magnitude and duration of the system's peak load compared to average load conditions. When resources to meet that load are plotted against a load duration curve, the observer can deduce the sufficiency of those existing and planned resources. Figure 4 also features the resources (capacity contracts and LNG) that comprise SCE&G's portfolio of DCGT capacity, and SCE&G's actual vaporization of LNG for the 2016 / 2017 gas year.[17] The DCGT capacity contracts to serve SCE&G locations include all of SCE&G's contracted quantities, the firm quantities of Columbia Energy Center contracts, and SCANA Energy Marketing's (SEMI's) firm delivery capacity to SCE&G's Jasper County plant.

---

[15] Federal regulation requires that the interstate gas companies it regulates post data related to all firm contracts, including: the shipper, their primary receipt and delivery locations, associated point quantities, total transportation capacity, and start and end dates of contracts.

[16] A "gas year" runs from November 1, of one year to October 31, of the following year.

[17] LNG vaporization involves gasification of the LNG stored in the insulated holding tanks. LNG which is natural gas chilled to -260 degrees Fahrenheit is ~$1/600^{th}$ the volume of natural gas in its gaseous state. 1 cubic foot of LNG = ~600 cubic feet of natural gas and 12.1 gallons of LNG = 1,000 cubic feet or 1 Mcf of natural gas.

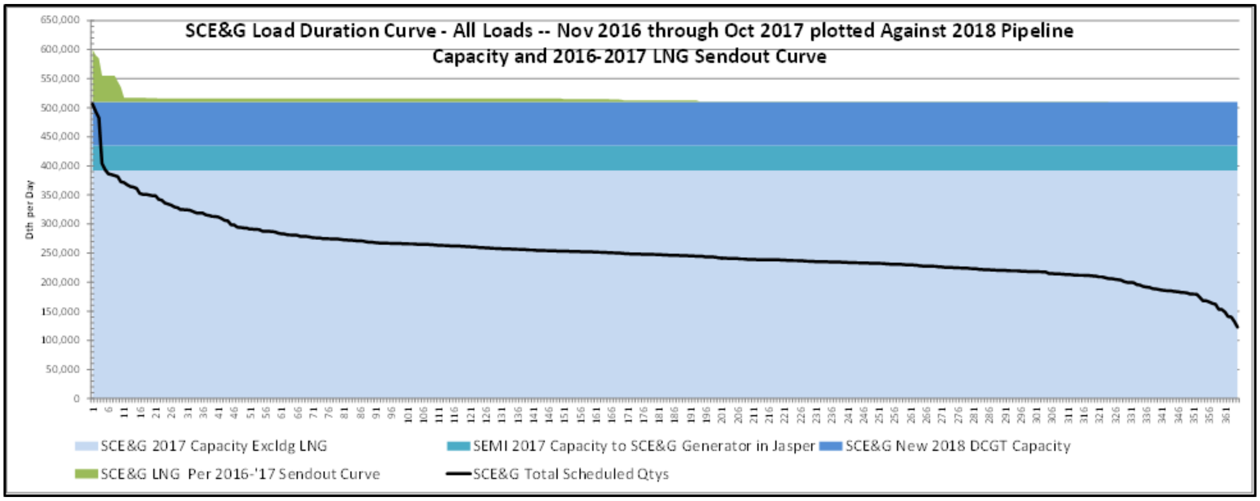


Figure 4: SCE&G load duration curve – all loads – November 1, 2016 through October 31, 2017 plotted against 2018 contracted pipeline capacity and 2016-2017 SCE&G LNG sendout curve

As can be seen in Figure 4, SCE&G's gas peak is "needle" in nature and lasts only about six to ten days.[18] In addition, it is notable that the actual dispatch (vaporization) of LNG from SCE&G's two LNG terminals was nearly 100,000 Dthd at peak. This 100,000 Dthd is two-thirds of the peak rated send-out capability of those terminals according to data filed with the Federal Department of Transportation's Pipeline and Hazardous Materials Safety Agency, which registers the combined vaporization capacity at 154,000 Dthd.

Below, in Figure 5, Skipping Stone plotted DCGT's deliveries to SCE&G's distribution company locations (i.e., those locations other than SCE&G's DCGT-connected power plants) over the winter of 2016-2017. As seen from the full gas year load duration curve in Figure 4, and the full year daily scheduled quantity presented in Figure 3, the important part of the year for capacity sufficiency is the winter period. Demand for natural gas is highest in winter due to the combination of demand for heating with natural gas and demand for heating with electricity generated by gas-fired turbines and boilers. The peak daily sendouts of DCGT during the two highest non-coincident winter demand days for SCE&G's electric and gas demand in the past five years were 205,886 Dth per day and 361,241 Dth per day respectively. On these two days, SCE&G logged its two highest peak hours of electric demand (i.e., load). Skipping Stone's analysis of SCE&G peak demands[19] indicates SCE&G's highest absolute demand hours were in winter—a time when demand for gas for domestic heating is also highest.

---

[18] In any given gas year these 6 to 10 days are generally bunched together in groups of 1 to 3 over the 60 to 90 day period of December through February.

[19] Peak demand information was provided in responses to data requests regarding the 2017 Integrated Resource Plan.

Given the significance of the winter period, Figure 5 focuses on the load duration curve over the winter period. In addition, Skipping Stone estimated SCE&G gas division's growth in peak demand to 2027-2028 from 2016-2017, based upon the same growth rate that SCE&G projected its electric load would grow in 2017 (i.e., 0.9% per year). This number should be considered conservative. SCE&G has since revised its winter peak demand growth projection down to 0.8% per year in its 2018 Integrated Resource Plan.[20]

Then, Skipping Stone plotted just the 2018 contracted DCGT delivery capacity of SCE&G[21] that was contracted to its gas service locations (again, those locations other than SCE&G's DCGT-connected power plants). The purpose of this analysis is to present a picture of how sufficient existing (i.e., post-Charleston expansion) 2018 capacity of SCE&G's gas division would be in meeting the forecasted winter load duration curve ten years from now, in 2027-2028. Note that in Figure 5 below, any day that the available resources (the horizontal bars) exceed the black load duration lines, there is excess gas capacity held by SCE&G. On those days, the excess capacity is available for others served by DCGT.[22] On the few days where there is no excess gas capacity held by SCE&G, SCE&G is able to meet gas demand through sendout of stored LNG.

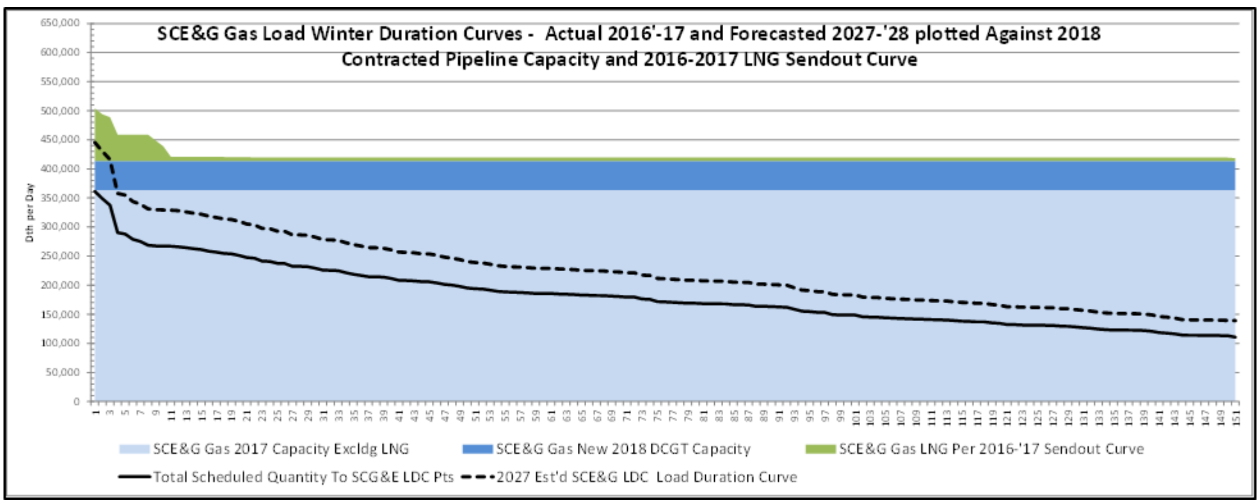


Figure 5: SCE&G gas load winter duration curves – actual 2016-2017 and forecasted 2027-2028 plotted against SCE&G gas contracted pipeline capacity and winter 2016-2017 LNG sendout curve

As was done for SCE&G's gas-only loads, Skipping Stone also plotted the load duration curve for SCE&G's electric loads. Figure 6 shows SCE&G's load duration curves in megawatt hours (MWh)[23] from the winters of 2012-2013, 2013-2014, 2014-2015, as well as a 2027-2018

---

[20] http://www.energy.sc.gov/files/view/2018%20SCE%26G%20IRP.pdf at 3.

[21] 2018 capacity includes the capacity associated with the Charleston expansion, which adds an additional 50,000 Dthd for the gas side of SCE&G.

[22] This "excess" can be made available by the holders of the capacity through sales (a.k.a. releases) of that capacity to others or by DCGT through sales of interruptible transportation. Both releases and interruptible transportation are considered the secondary market.

[23] A megawatt hour is 1 million watt hours or 1,000 kilowatt hours (kWh).

forecasted load curve. The 2027-2028 forecasted curve was developed by taking the highest winter peak hourly load (the 2014-2015 load of 4,970 MWh), growing that peak hourly load out to the winter of 2027-2028 using a 0.9% annual growth rate,[24] then developing a curve with that forecasted peak hour to match the 2014-2015 winter load shape.

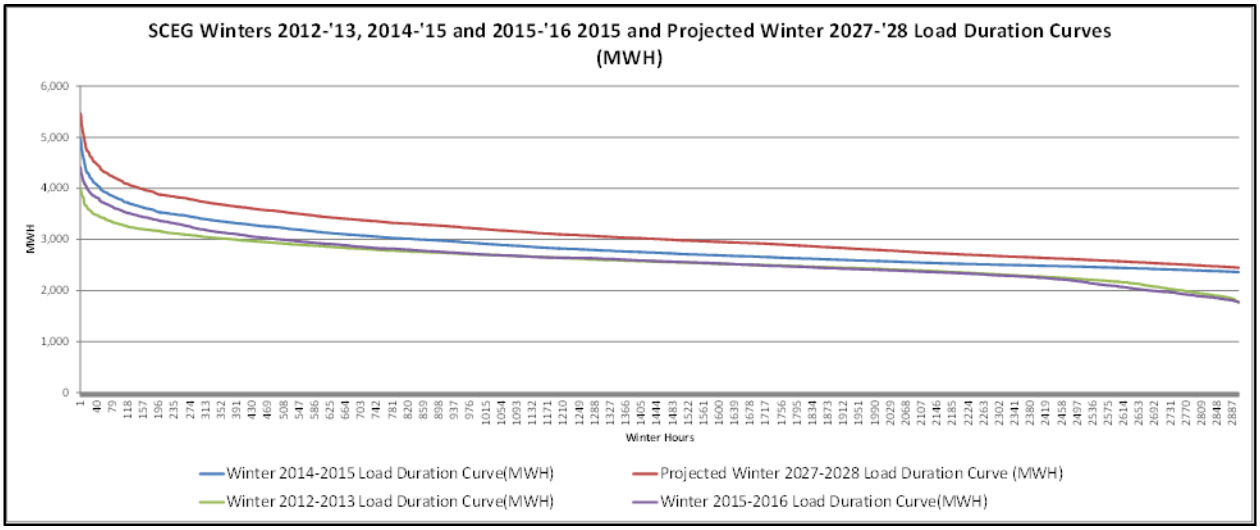


Figure 6: SCE&G 2012-2013, 2014-2015, and 2015-2016 winter load duration curves and 2027-2028 projected winter load duration curve

Finally, Figure 7 shows that existing generating resources are adequate to meet peak demand projected for the winter of 2027-2028 given planned 2018 DCGT upgrades. In Figure 7, Skipping Stone analyzed the electric generation resources SCE&G presented in its 2017 Integrated Resource Plan (IRP)[25] as being available in 2027, with adjustments to remove the cancelled nuclear plant and insert the Columbia Energy Center recently purchased by SCE&G. Then, for SCE&G's gas fired resources Skipping Stone used heat rates estimates (the amount of gas energy required to make a MWh of electricity)[26] to determine how many MW of generating capacity could be served by the SCE&G-electric's portfolio of pipeline capacity.

---

[24] This 0.9% this growth rate from SCE&G's 2017 IRP should be considered conservative as SCE&G has since revised its growth rate over this period down to 0.8%

[25] As this report was being finalized, SCE&G submitted its 2018 IRFP which anticipates an additional 540 MW combined cycle unit in 2023, which would nominally consume ~75,00 Dthd of natural gas. As discussed below, with respect to capacity on DCGT, this unit, depending on its location within SC will potentially require an upgrade or expansion of DCGT; however, as also discussed in this report, there is sufficient capacity on Transco to supply this quantity of gas to DCGT. In addition, SCE&G noted in its 2018 IRP that it anticipates participating in Transco's Southeastern Trail expansion, which will increase capacity on Transco from the interconnect with Dominion's Cove Point LNG pipeline to South Carolina and Alabama. This project would make additional gas available to DCGT, but again DCGT would have to increase capacity to serve the proposed 2023 540 MW plant, depending on specific location of the plant.

[26] Skipping Stone analyzed Federal Energy Information Agency data on generated MWh and associated fuel use by plant.

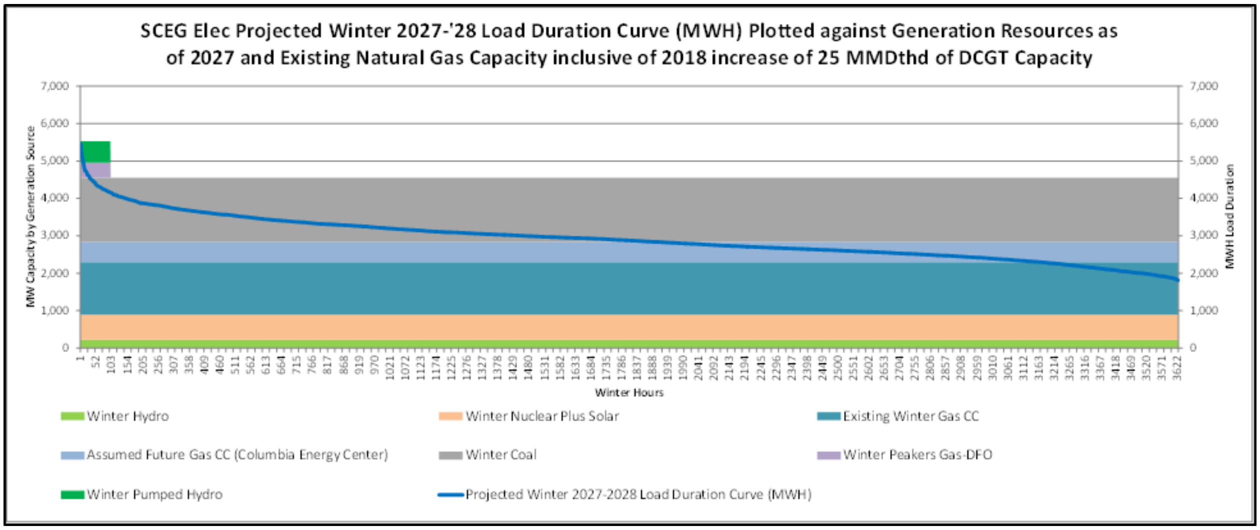


Figure 7: SCE&G electric 2027-2028 projected winter load duration curve (MWh) plotted against generation resources as of 2027[27] and existing natural gas capacity of SCE&G-electric generation, including the 25 MMDthd increase of DCGT capacity in 2018[28]

As can also be seen in Figure 7, current natural gas capacity is sufficient to power SCE&G's generation resources for the next decade. As with Figure 5, when the horizontal bars (the resources) are greater than the load duration line, there exist resources in excess of demand. Here, SCE&G's peaking resources – pumped hydro and natural gas plants – remain adequate to meet projected peak demand through 2027. Notably, Skipping Stone assumed gas-fired resources would be run prior to coal-fired resources. In addition, given that SCE&G's fleet of Peakers can be fired with either diesel fuel oil or gas, should gas supplies (e.g., LNG) be preferred, that source could replace diesel fuel oil as the fuel used by the Peakers. In other words, there is enough capacity to meet SCE&G's projected generation needs over the next decade *and* transition the Company's Peaker plants to natural gas.

---

[27] This does not include the 2018 SCE&G proposed 2023 540 MW plant described above. Development of that new generating resource would provide additional capacity on top of the existing resources and the Columbia Energy Center, which are already adequate to meet projected electric demand.

[28] In Figure 7 electric load is charted in hours—the ~3,600 in the 151 days of a gas year's winter. To chart the electric-side hours against the gas industry convention of days, Skipping Stone divided SCE&G's daily gas capacity by 24 and used that hourly capacity to calculate the hourly production of electricity possible with that hourly capacity of gas. It should be noted that except for the coldest days of winter, when pipelines generally require their shippers to keep hourly takes at 1/24th of daily capacity, pipelines generally permit power plants to ramp (i.e., take gas) at rates greater than 1/24th and de-ramp to rates of take lesser than 1/24th of daily scheduled capacity.

Discussion of In-State Natural Gas Capacity Issues

DCGT does not have capacity that is available to be sold to customers within the state on a firm basis without first making an expansion. DCGT is currently expanding its system by approximately 9%, with completion expected before the end of summer 2018. That expansion was facilitated by customers signing up for 10- to 20-year contracts sufficient to pay for construction of the new facilities in South Carolina.

In general, to reserve pipeline capacity, potential customers, such as local distribution companies, municipalities, power generators, and industrial users, contract with the pipeline company to pay fixed reservation charges for the right to use the pipeline as well as to reserve pipeline capacity.

To further expand DCGT within South Carolina, SCE&G is likely a necessary customer. As discussed below, there is plenty of capacity to the state on Transco; however, firm capacity within the areas of the state covered solely by DCGT is more problematic. Because it has existing customers to whom it can pass the costs of expansion or extension prior to getting new customers to absorb those costs, SCE&G is the most likely entity to subscribe to further expansion(s) of DCGT. SCE&G also has LNG which it can use to meet peaks in demand until new DCGT capacity can catch up. And, finally, SCE&G is most likely to be able to both identify (and reveal to regulators) potential new loads on the system.

Skipping Stone's analysis indicates that to the extent additional firm demand, un-forecasted by SCE&G were to materialize within South Carolina, DCGT would likely need to expand its in-state pipeline facilities to serve that demand on a firm year-round basis. These two points are evidenced by the most recent expansion of DCGT where SCE&G's gas and electric divisions separately subscribed to 50,000 Dthd and 25,000 Dthd respectively. Two industrial customers also subscribed to an additional 5,000 Dthd of firm capacity on DCGT's "Charleston" project. However, in spite of this 80,000 Dthd expansion of service by these customers on the DCGT system, there is no evidence that any of these DCGT expansion shippers subscribed to any capacity on Transco or SONAT to feed their new DCGT capacity. Skipping Stone will show, below, that this lack of commensurate subscription to expansion capacity on Transco (or SONAT) is a sensible strategy, given the abundance of capacity available to South Carolina on Transco.

While evidence shows that there is ample capacity available on Transco to serve consumers in South Carolina, none of that capacity is currently un-contracted. This means that customers in the state with capacity on DCGT will buy gas delivered by Transco from one or more of the holders of capacity on Transco. As discussed below, this ample capacity on Transco is in part due to the ability of Transco shippers to segment their Transco capacity, enabling them to physically receive and deliver more gas than their stated contracted capacity. However, should industrial, municipal, or other shippers on DCGT want their own capacity on Transco, as opposed to buying gas competitively from those shippers on Transco able to deliver to South Carolina, then such customers would need to subscribe to Transco capacity, likely for a term of 20 years.

In sum, industrial customers or others in South Carolina that want firm delivery service through SCE&G have to first get firm on SCE&G. Then, if they also want "Firm" service for gas from Transco, they have several choices: 1) they could arrange with a Seller with firm service on Transco to buy gas on a "firm basis" whether for a short or long term – to be negotiated, 2) they could get a shipper with capacity to serve South Carolina to release some of their capacity to them (i.e., capacity release); or 3) they could subscribe to an expansion of Transco.

Gas users in South Carolina have anecdotally indicated to Skipping Stone that their "Firm Service" now gets cut often because there is no excess pipeline capacity to serve existing loads during periods of high demand. This is a complicated truth. First, service for most gas users in South Carolina is provided by SCE&G, which under its in-state "Firm Service" tariff can "cut off" gas service within all or parts of their service area to ensure adequate gas is available to meet "essential needs," such as residential customers, hospitals, police stations, and schools. However, with respect to "Firm Service" on an interstate pipeline (like DCGT, SONAT, Elba Express or Transco), shippers scheduling gas up to their Maximum Contract Quantity cannot get cut by these interstate pipelines. From the end users' perspective, this difference may seem unimportant. But from a planning perspective, it is essential to understanding what infrastructure improvements may be required to eliminate such periodic curtailments in service.

For SCE&G to provide "Firm Service" at all times to all gas users in the state, SCE&G may have to both expand its system and subscribe to an expansion of the DCGT system. In both cases, this would be an economic decision by SCE&G which may also have regulatory implications as to cost allocation of such expansion(s) among SCE&G ratepayers. Factors like access to water, electricity, roads, rails, and population with skills will no doubt influence whether and where future industrial development is likely to occur, and thereby where in-state gas infrastructure may need to be expanded or extended. In sum, to the extent that there may be regional shortages of firm capacity, these are the result of in-state constraints on the DCGT system and not due to any capacity shortage on the existing interstate pipeline system. Expansion of in-state distribution capacity depends on regional economic factors, such as population density and industrial capacity, that are largely unaffected by the overall interstate natural gas supply to South Carolina.

Capacity on Other Interstate Pipelines is Sufficient to Supply DCGT

Because DCGT is served by other interstate pipelines and LNG facilities, Skipping Stone also analyzed the sufficiency of capacity of the pipelines and LNG sources serving DCGT and found existing and soon-to-be-existing capacity was substantially more than sufficient to serve the requirements that DCGT will have in order to meet SCE&G's demands through at least the winter of 2027-2028. Holders of capacity on DCGT seldom have more than relatively small percentages of their DCGT capacity holding(s) on the pipelines serving DCGT, especially DCGT shippers whose primary receipts onto their DCGT contracts are at Transco interconnects. Skipping Stone specifically analyzed available contracted capacity and scheduled flows during this winter's "bomb cyclone" period of extreme weather and persistent high demand and found that interstate pipelines were not only sufficient to meet experienced demand, they had additional capacity that could have fed DCGT capacity. LNG resources also could have met even higher demand.

As discussed above, DCGT — the interstate pipeline whose facilities are almost wholly within South Carolina[29]— is served by other interstate pipelines or federally regulated interstate facilities.[30] Those pipelines are SONAT, Transco, and EEC. In addition, DCGT is served by SLNG, and the SCE&G owned and operated LNG facilities referred to as the Bushy Park and Salley facilities. While SLNG is soon to also become an LNG export terminal, it retains its LNG vaporization capability and capacity.[31] The map below, Figure 8, presents the pipeline and LNG facilities in and serving South Carolina.

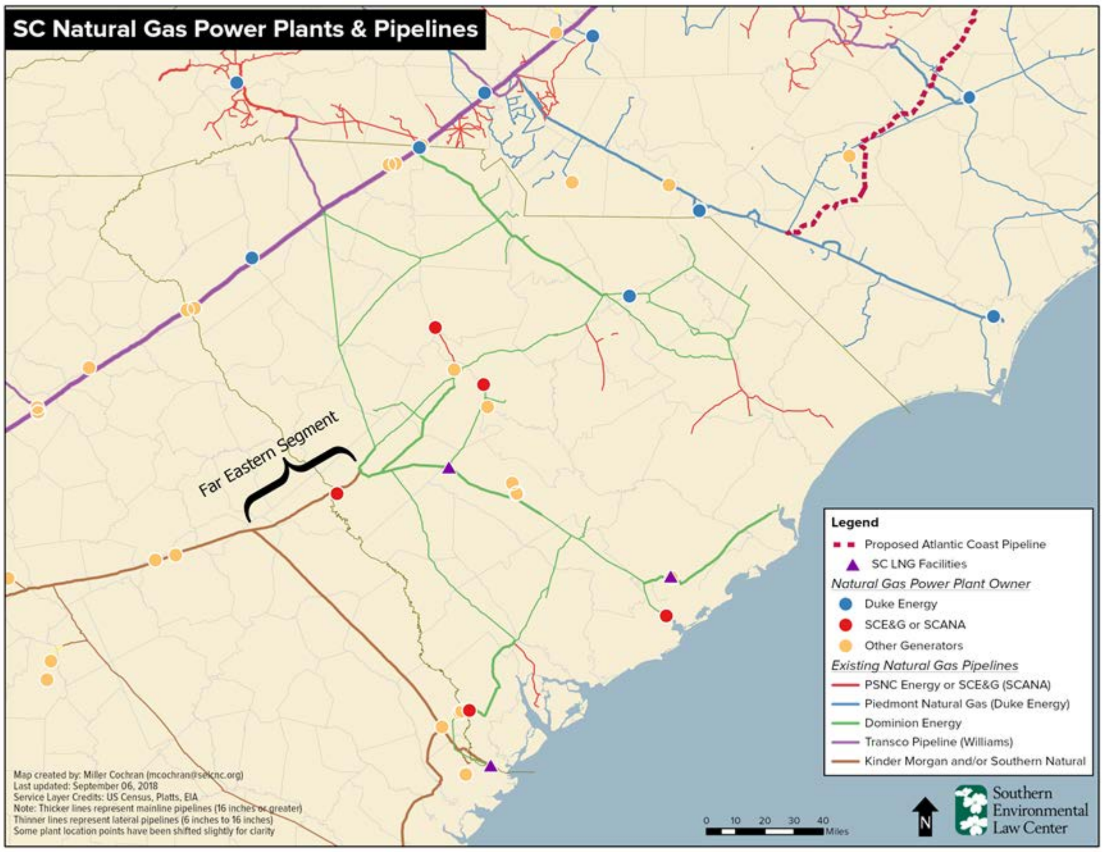


Figure 8: 2017 Map of Natural Gas Pipelines, LNG facilities, SCE&G Gas-Fired Power Plants, and Duke Gas-fired Power Plant

---

[29] DCGT extends a short distance into Georgia where it interconnects with the EEC and SLNG.

[30] The Southern LNG facilities associated with the Elba Island LNG Terminal are considered federally regulated interstate facilities.

[31] SLNG's storage capacity is about 11.9 Bcf and its vaporization capacity is rated at 1.7 Billion cubic feet per day (Bcfd). The SCE&G LNG facilities are capable of storing LNG equivalent to about 1.9 Bcf and vaporizing 154,500 Dth per day. One Dth equals 1 Million British Thermal Units (Btu). One Million BTUs is the energy it takes to turn 100 pints of water (each a pound) into steam. One Dth is approximately the amount of energy in 1,000 cubic feet of natural gas. One thousand cubic feet is denoted as 1 Mcf. There are 1,000,000 Mcf in a Bcf.

To assess interstate capacity available to South Carolina and its utilization, Skipping Stone looked at all the pipelines serving the state, collected the contracted capacity of the lines that contributed to natural gas infrastructure, and plotted those contracted capacities against recent flow history.

SONAT

SONAT, the Kinder Morgan/Southern Company pipeline shown in Figure 8, extends from East Texas through Louisiana, Mississippi, Alabama, Georgia, South Carolina, and parts of northern Florida. Skipping Stone has labeled the east west line that runs from the north-south line into South Carolina and terminates in or around Aiken, South Carolina the Far Eastern segment of the SONAT system (as labeled in the map above).

Appendix B presents Skipping Stone's analysis of capacity and scheduled deliveries (i.e., daily utilization) along the Far Eastern segment of SONAT. The analysis demonstrates that SONAT rarely flows (schedules) more than its contracted firm capacity on this Far Eastern segment, indicating that the line is fully subscribed and there is little operationally available capacity in excess of contracted capacity. In addition, Skipping Stone analyzed the contracted firm capacity and scheduled flows at the two locations relevant for SCE&G: DCGT, which receives gas from SONAT at the terminus of the Far Eastern segment, and for which SCE&G holds nearly 70% of all delivery capacity; and at the SCE&G power plant location in Aiken County, South Carolina. The sum of flows to the two locations exceeds contracted firm delivery capacity, often by more than 50,000 Dthd or 120% of contracted firm capacity. Clearly the level of demand being expressed at these two locations is greater than the contracted firm delivery capacity on SONAT to these two locations, whether due to price, demand, or a combination of the two. As a result, it appears that the whole SONAT Far Eastern segment and the northwestern portion of DCGT, especially as it relates to deliveries to DCGT for onward delivery elsewhere in South Carolina, are likely constrained. Because DCGT lies at the far eastern end of the SONAT system, SONAT cannot deliver more gas on a firm, year-round basis to DCGT without an expansion.

TRANSCO

The other main pipeline serving South Carolina, and the largest pipeline by capacity in the United States, is Transco. Transco runs from South Texas to New York, with another line—the Leidy Line—running from northern New Jersey to north central Pennsylvania. The Leidy Line was built to connect storage fields in Pennsylvania with the Transco south to north mainline running from Texas. Since the development of the Marcellus shale, the Leidy Line now also carries gas from the Marcellus to New York, the greater Northeast area, and all the way to the Gulf Coast. In effect, Transco is now a bi-directional line[32] that contractually moves gas both from the Gulf Coast to the New York market and from the prolific Marcellus to the Gulf Coast.

[32] In fact, Transco may now be considered a 1,000+ mile long pressure vessel with gas coming in and going out all along its extent. The net northward, net southward or null point (i.e., neither northward nor southward) flows changes daily or sub-daily with the particular mixtures of supplies and markets attached to the system.

Transco has 6 zones. Texas, Louisiana, and Mississippi are in Zones 1, 2, and 3. Alabama and Georgia are in Zone 4. South Carolina, North Carolina, and Virginia are in Zone 5. And Maryland, Pennsylvania, New Jersey, and New York are in Zone 6.

Appendix C presents Skipping Stone's analysis of capacity and scheduled deliveries (i.e., daily utilization) from Transco to DCGT and points in South Carolina. The analysis demonstrates that there is excess capacity available in Transco Zone 5. Specifically, the analysis shows that while firm *contracted capacity* on Transco to DCGT and to South Carolina points is much less than demanded capacity—as demonstrated by the fact that quantities of gas delivered by Transco to DCGT and South Carolina points usually exceed, and often greatly exceed, contracted capacity[33]—there is more than enough *available capacity* to serve all South Carolina points.

Skipping Stone plotted the balance of deliveries to all Zone 5 locations against available capacity into and through Zone 5 to illustrate that this is true even in times of extremely high demand for natural gas.

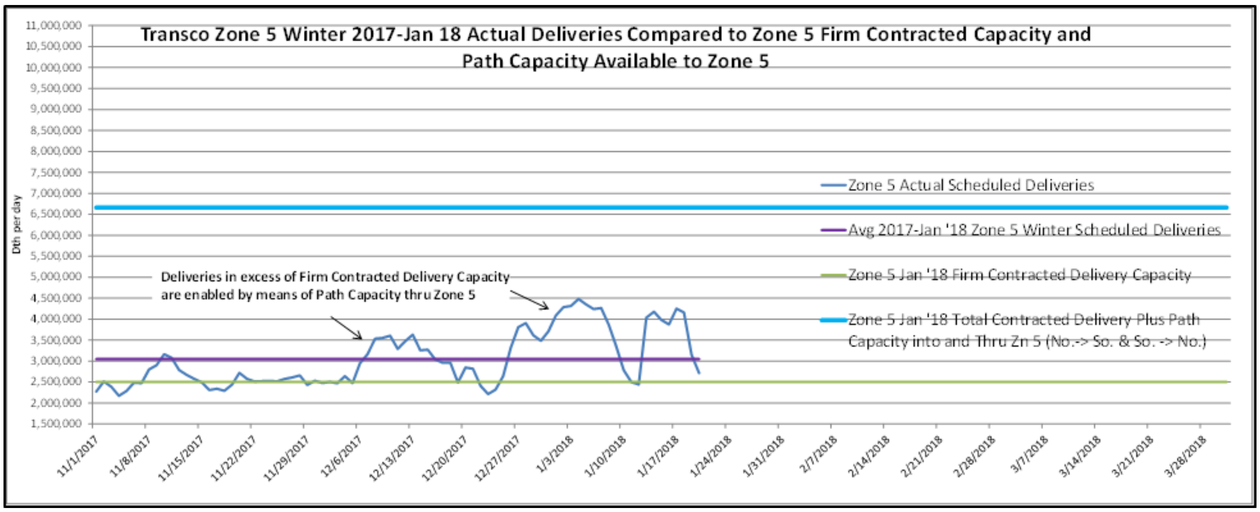


Figure 9: Transco Zone 5 winter 2017 through January 2018 actual deliveries compared to Zone 5 firm contracted capacity and path capacity available to Zone 5

Figure 9 shows that there was excess available capacity in Zone 5 this past winter. Even during the "bomb cyclone" event in early January 2018 when actual deliveries reached 4.5 Bcfd, there was still another 2.0 Bcfd of available capacity. There is more than 6.5 Bcfd available at Zone 5 delivery points, even though there is only 2.5 Bcfd of subscribed Transco delivery capacity at these points (including approximately 0.29 Bcfd of firm South Carolina delivery point capacity).

33 Firm contracted capacity on Transco to DCGT in 2018 is about 150,000 Dthd. Deliveries to DCGT from Transco routinely throughout the year exceed the contracted capacity amount by 50,000 Dthd (about 130%), and often by 100,000 Dthd (about 160%). Firm contracted capacity on Transco to South Carolina locations in 2018 is about 300,000 Dthd (287,433 Dthd). Deliveries to South Carolina locations peaked at 500,000 Dthd (0.5 Bcfd) higher than contracted and were routinely twice the amount of contracted firm capacity (i.e., 600,000 Dthd).

The reason so much more gas can be delivered than the quantity of firm delivery point capacity is that holders of capacity on DCGT that require more gas from Transco than their firm contracted Transco quantities can buy gas from shippers on Transco that have capacity "past" DCGT. For instance, a shipper with receipt capacity in Zones 1, 2, 3, or 4 with delivery capacity in Zones 5 or 6 can deliver gas to DCGT in Zone 5 even if the DCGT point is not on their contract. Likewise, a shipper with receipt capacity in Zones 5 or 6 with delivery capacity in Zones 4 or 5 can deliver gas to DCGT in Zone 5, again, even if the DCGT point is not on their contract. This sort of capacity is called "path capacity." Shippers holding path capacity can make sales (i.e., deliveries) to the South Carolina and other Zone 5 points without consuming the totality of their path capacity.

A simple way to think about path capacity is by analogy to buying a seat on a train from Florida to New York. A ticket holder can get on in Florida, get off in South Carolina, race to North Carolina, get on the train again, get off in Southern Virginia, get back on in Northern Virginia and finally get off in New York. As long as there are never "two ticket holders" in the seat at any given time, this is permitted in the gas pipeline business so long as the pipeline in question is "pathed."[34]

The fact that Transco is bi-directional greatly expands the available capacity of the system, without the addition of new pipes in the ground. For this reason, path capacity on Transco includes: (1) north to south passing South Carolina, (2) south to north capacity passing South Carolina, and (3) the contracted delivery capacity to South Carolina points. Extra deliveries are possible because capacity owners can schedule multiple receipts and deliveries along their "contracted paths." Shippers have rights to the "path" between their contracted receipt and delivery points and can segment this capacity and use it to deliver gas throughout that capacity in a myriad of ways. Imagine a line that runs from south to north; and, as shown in Figure 10, from the receipt point at "A" to a delivery point at "F."

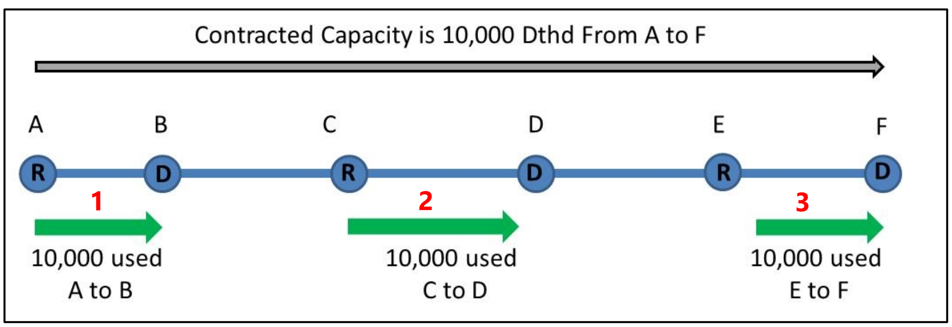


Figure 10: Segmentation path capacity depiction[35]

[34] While both Transco and SONAT are "path pipelines," because SONAT's points along the far Eastern segment are "at the end of its line," as a practical matter gas on SONAT moves only to the Far Eastern segment. While SONAT has contracts to move gas from the east to the west –in particular from SLNG in the east to the west – the Far Eastern segment does not physically (or have the firm contractual obligation to) receive gas that moves to the west.

[35] "R" refers to capacity received and "D" refers to capacity delivered. The numbered green arrows represent separate transactions.

Imagine that in Figure 10 “A” is in Zone 4; “B,” “C,” and “D” are in Zone 5; and “E” and “F” are in Zone 6. The shipper with 10,000 Dthd from “A” to “F” can first receive gas in Zone 4 to deliver in Zone 5, then obtain additional gas in Zone 5 to drop off further along in Zone 5, then pick up additional gas (e.g., at point “E” in Zone 6), and finally deliver the remaining gas to point “F” further along in Zone 6. In this example, segmentation enabled a 10,000 Dthd path to be used to move 30,000 Dthd—three times the contracted path capacity. This strategy allows for multiple deliveries within and across Zones as long as no more than 10,000 Dthd is used along any segment; no overlapping is permitted.

This example actually underestimates the amount of gas that could be moved because it shows path “A to F” (south to north), but does not show the “F to A” (north to south) paths of capacity which can be scheduled simultaneously with “A to F” (south to north) paths of capacity. The reversed path (“F to A”) is possible on Transco due to capacity expansion projects that recently came into service, and another 1.3 Bcfd can be reversed when additional projects come into service later in 2018. Pathing (“A to F” and “F to A”) enables the current approximately 6.5 Bcfd of capacity available to Zone 5, as seen in Figure 9, to grow to about 7.3 Bcfd on a once-through basis. Even greater quantities will be possible with segmentation once the final phase of Transco’s Atlantic Sunrise project comes into service, expanding the Transco system and allowing increased deliveries from Pennsylvania gas fields to the mid-Atlantic and southeastern states.

In addition to segmentation, bidirectional flow also enables “delivery by backhaul” or “delivery by displacement.” This is the ability of a customer to deliver gas to a pipeline at or near that pipeline’s point of demand and for that customer to request the same quantity at or near a location along the path over which that demand location is being served. Thus, while gas would not be physically transported upstream in the pipeline system (i.e. north to south historically), gas could be effectively transported upstream by taking gas out upstream (in the South) and delivering the same quantity of gas to the pipeline downstream (in the North).

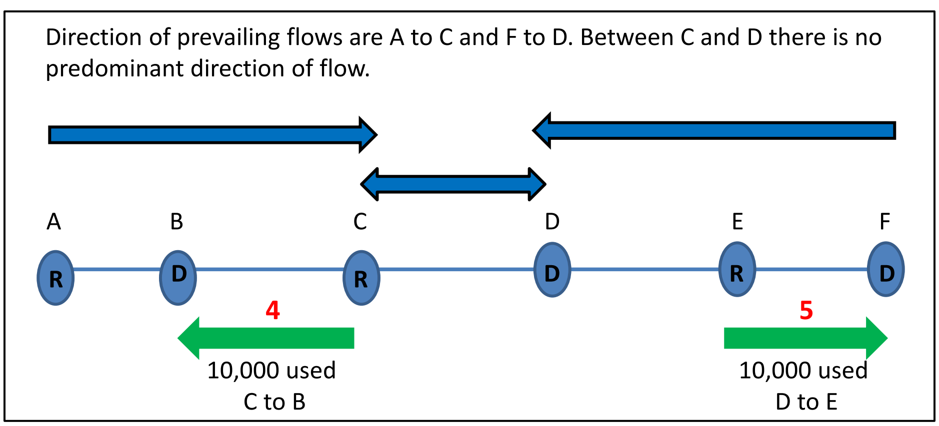


Figure 11: Backhaul / delivery by displacement path capacity depiction[36]

[36] “R” refers to capacity received and “D” refers to capacity delivered. The numbered green arrows represent separate transactions.

Transactions 4 and 5 in Figure 11 are "backhaul" or "delivery by displacement" transactions. Where the prevailing flows presented in this Figure coexist with the contracted capacity in Figure 10, all 5 green arrow transactions characterized in Figures 10 and 11 (i.e., 50,000 Dthd of transactions) can occur on a contracted path of 10,000 Dthd.[37]

Most of the new capacity added to Transco over the last five years that is available to South Carolina is not capacity that is slated for any particular end user. Of the 3.3 Bcfd of year-round capacity added to Transco since 2013, 2.307 Bcfd is not held by utilities for their power plants or distribution systems. Instead, it is held by companies that produce gas, market gas, or function as asset managers[38] for other entities that have transportation agreements with pipelines. Collectively, these companies are known as producer-marketer-asset manager companies or PMAs. Unlike electric utilities or local gas distribution companies, PMAs do not have a franchised service territory to which they must direct their capacity in order to serve their own power plants or distribution utilities (i.e., native load). Rather, PMAs contract with all types of buyers to deliver gas at competitive market prices using the pipeline capacity the PMAs have signed up for and/or control. In other words, 2.307 Bcfd of the new capacity into Transco Zone 5 is available at market prices for any end user, gas distributor, or marketer that is using, distributing, or selling gas in South Carolina.

In addition to the 2.307 Bcfd of added year-round non-utility capacity, local gas distribution companies hold another 0.527 Bcfd of year-round capacity to or through Zone 5 (as part of the overall new capacity). Due to the particularities of the markets served by local distribution companies, which do not need capacity during the off-peak period (including summer); this additional capacity would be available to electric generators needing supply in the summer. This brings the total new (since 2013) off-peak / summer capacity that is held by PMAs and local distribution companies to and through Zone 5 to a whopping 2.834 Bcfd. To put this recently added, largely unspoken for, 2.834 Bcfd of added capacity in perspective, this capacity is equal to nearly ten times the Transco firm contracted delivery capacity to South Carolina points of Transco. Also notably, referring to Figure 3, this 2.834 Bcfd of added capacity is five times the peak usage shown in Figure 3 and nearly 9.6 times the average flow over the period depicted in Figure 3.

Skipping Stone's analysis shows that there is 2.0 Bcfd of additional capacity available on Transco to DCGT and South Carolina points in the most high-demand periods of winter, and much more available capacity in the summer, including 2.834 Bcfd just from PMAs and local distribution companies. With substantial capacity remaining on DCGT sufficient to meet SCE&G's projected demands, the Transco-to-DCGT path is viable for meeting SCE&G's projected future demands.

---

[37] For instance, this segmentation allows gas to enter Transco in Zone 5 from TCO, East Tennessee Natural Gas (ETNG), DTI, EEC (from Elba Island, Dominion Cove Point(from Cove Point LNG), and Piedmont LNG. Plus, gas can enter into Zone 6 from Texas Eastern, Tennessee, Transco LNG, TCO and DTI (Storage).

[38] Asset managers can be any company, including producers or marketers, which contracts with holders of pipeline capacity to market gas through the holder's pipeline capacity when the original holder has no need for the capacity.

Elba Express Company

The EEC interconnects with Transco at the border of Transco's Zone 4 (Georgia) and Transco's Zone 5 (South Carolina). The EEC's original purpose was to receive up to 1.1 Bcfd of vaporized LNG from the Elba Island import facility operated by SLNG and deliver that vaporized LNG north and west to Transco for onward delivery on Transco. EEC still has a firm contract to receive nearly 1 Bcfd of vaporized gas from SLNG and deliver it to Transco. However, EEC can now operate bi-directionally, receiving gas at Transco and delivering to SONAT (for delivery across the SONAT system), to SLNG (the Elba Island facilities) for delivery to DCGT, and to a power plant in Effingham County, Georgia. Once the Elba Island LNG facility becomes an LNG Export facility, the main annual purpose of EEC will be to move gas from Transco to Elba Island for liquefaction and export.

EEC currently receives the overwhelming majority of its gas from Transco. In 2017, deliveries by Transco to EEC were pretty evenly divided between Georgia and South Carolina. EEC then delivered a slight majority of the gas it received from Transco to SONAT, which takes the gas to SONAT markets in Georgia and Florida; and delivered the other half of the supply it received from Transco to DCGT through the SLNG facilities[39]. Skipping Stone therefore decided to count deliveries by Transco to South Carolina—including deliveries to EEC in South Carolina—as supplies available to South Carolina in its analysis of Transco described above. The other half of EEC receipts from Transco that were made in Georgia (i.e., Zone 4 Transco) were not counted as South Carolina-available supplies. EEC ultimately neither contributes to, nor detracts from, capacity available to South Carolina because the quantity of gas EEC gets from Transco in South Carolina is approximately the same as the quantity of gas that goes from EEC through SLNG to DCGT.

Southern LNG – The Elba Island LNG Facility

Since 1974 the Elba Island Import Facility has alternated between being active and inactive with changes in regulation and economic factors. In 2003, 2006, and 2010, the facility expanded until its storage capacity reached about 11.5 Bcf and its vaporization capacity reached 1.7 Bcfd. In 2013, the owners decided to add liquefaction capability to allow the facility to both import and export, as well as to liquefy and vaporize.

SLNG vaporized gas this winter—about 5.7 Bcf between December 1, 2017 and January 21, 2018. Its peak vaporization was 684,000 Bcfd on January 17, 2018. It is possible that all 1.7 Bcfd of SLNG's vaporized gas could be moved to market through SONAT, DCGT, and EEC. That said, for either SONAT or DCGT to take all that SLNG could provide, the demand on their respective systems would need to be higher to absorb the gas.[40]

---

[39] Notably, the gas that DCGT receives from SLNG by this means can serve DCGT markets in its limited Zone 2 geographical area; currently, there is limited transfer capability on the DCGT system between its Zone 2 and its predominant, Zone 1 geographical service area.

[40] In other words, it would have to either be really cold with associated heating and gas-fired generation demand, or really hot with air-conditioning demand met by gas-fired generation.

Liquefaction capability is expected to begin in the latter half of 2018. The liquefaction capability will be approximately 0.3 Bcfd. With about 11 Bcf of cycle-able LNG Storage and 0.3 Bcfd of liquefaction capability, the facility would be able to fill all storage tanks to optimum levels in about 28 days, and to fill a tanker every 10 days.[41] However, because the entities that own the liquefaction and vaporization capability are in the business of making money, it is likely that the SLNG facility would provide a significant benefit to South Carolina in addition to supplying tankers for export. This winter, for example, spot prices encouraged vaporization of LNG and most LNG terminals hooked into interstate pipelines vaporized gas this winter.

Elba Island could provide as much as 2.0 Bcfd of surge supply to South Carolina in the years to come. As a storage and vaporization terminal, Elba and the entities with capacity on pipelines to deliver gas for liquefaction could respond to price signals as follows. The entities shipping gas to Elba could divert their approximately 0.3 Bcfd to markets along Transco (including in South Carolina) and sell the gas in the United States rather than liquefying that particular quantity. Then, the party(ies) with LNG in the storage tanks can vaporize LNG and inject it into the pipelines serving South Carolina (i.e., DCGT, SONAT for delivery to its Far Eastern segment as well as potentially back into Transco via EEC). In this way, if the demand was sufficient, as much as 2.0 Bcfd of surge supply could be made available to South Carolina markets (0.3 Bcfd of diverted supply plus as much as 1.7 Bcfd of vaporized supply for a total of 2.0 Bcfd). Moreover, depending on contracting structures, buying LNG to meet the needle peaks like those observed in SCE&G's load duration curves, can be far more economical than incurring the fixed costs associated with a pipeline expansion. This remains true to the extent that the LNG comes into the respective system(s) at locations where the LNG meets demand and frees up other supplies to meet other markets, all with the same existing pipe capacity. As Skipping Stone will discuss below, if there are local constraints or lack of facilities within South Carolina (as opposed to there being a lack of facilities to South Carolina), then addressing those local, in-state constraints is fundamentally a matter of economics, not of physics or hydraulic capacity.

Additional Interstate Natural Gas Capacity Is Not Necessary to Meet Demand in Underserviced Regions of South Carolina

Skipping Stone interviewed several representatives of commercial and industrial entities concerned about the sufficiency of South Carolina's current natural gas infrastructure to serve continued economic growth in the eastern and northeastern counties of the state. These representatives related their perception that South Carolina gas infrastructure is constrained and that there is no available year-round firm natural gas capacity for industrial use.

Skipping Stone reiterates what was noted above — *there is ample pipeline capacity to DCGT and to South Carolina as a general matter*. To the extent that industrial users have difficulty obtaining firm contracts from DCGT's dominant customer, SCE&G, this is not due to inadequate interstate pipeline capacity to South Carolina; rather it is due to insufficient pipeline (and

[41] Most LNG tankers have about 3 Bcf of tankage range. This rate of storage would be possible if no gas is stored for later vaporization.

distribution—i.e., SCE&G) capacity within South Carolina. This section explores why the eastern and northeastern counties in South Carolina are currently underserviced by natural gas local distribution companies and why wholesale gas pipeline service expansion into this region is not dependent on additional interstate capacity being brought into South Carolina.

Expansion of Local Gas Distribution Service vs. Expansion of Wholesale Gas Pipeline Service

To begin, it is important to understand that the economics, allocation of risk, and contract structure of local gas distribution service extensions and interstate pipeline expansions are very different.

In the local gas distribution business, extensions are done on a "build it and believe they will come" basis. In areas of existing construction, gas mains are laid down and gas company personnel and heating contractors sell conversion to gas packages to homeowners and businesses. This arrangement puts most of the risk on the local distribution company because ratepayers are typically shielded by regulatory rules that dictate the extension cost per new service location that can be automatically put into rates. Thus, an extension into an un-serviced region is made based on market research, polling, and possibly pre-selling activities. The company must determine—through an evaluation of potential service sales and adoption penetration rates—if the extension will eventually generate enough new service hook-ups to generate a profit. There is no guarantee that customers will take service once the distribution lines are built and there is no guarantee of a customer-originating revenue stream. Profits are only realized, if at all, long after the costs of extension are sunk.

In the interstate pipeline business, by contrast, extensions are done on "contract to pay me for ten to twenty years to cover my costs and profits and I will build it" basis. This means that allocation of risk is established prior to construction. Construction proceeds only once the party making the investment and the party receiving service and paying for the investment reach agreement and execute a contract that covers investment costs, level of service obligation, and the payment stream to the pipeline company over time.

Local Distribution Company Expansion is Not Inhibited by Lack of Interstate Pipeline Capacity

To gauge the potential size of areas of South Carolina that are un- or underserved by gas distribution companies and the markets they serve,[42] and assess why those areas may be un- or underserviced, Skipping Stone performed a simplified desktop analysis to identify their population density and heating characteristics.

Of the 99 postal zip codes[43] in the 12 eastern and northeastern South Carolina counties (the Pee Dee region) anecdotally noted as un/underserviced, 32 are wholly or partially served by

[42] Local distribution companies serve all their customers, residential, commercial and, for the most part, including their industrial customers as well, with the same facilities.

[43] These 99 zip codes corresponded to physical routes. An additional 12 zip codes were P.O. boxes in those counties.

SCE&G and 67 are not served by SCE&G.[44] SCE&G is the only local distribution company operating in the eastern and northeastern areas of South Carolina. Gas service is available to about 64% of the total population in these 12 counties (about 533,000 people of the total population of 834,000). In areas where gas service is available, population density is much higher — 104 postal locations (dwellings and businesses) per mi^2 in serviced areas compared to 42 postal locations per mi^2 in un-serviced areas.[45]

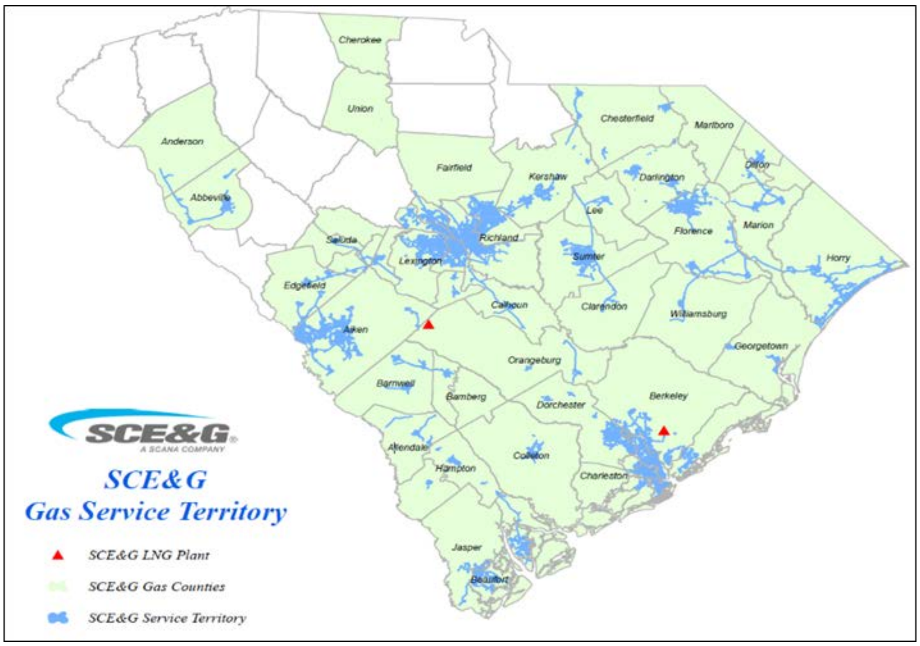


Figure 12: SCE&G service territory[46]

Postal locations in un-serviced areas are, on average, 14 acres apart.[47] Locations are not evenly spaced on a grid, but even so this density is extremely sparse.

Skipping Stone also examined census data for the same 12 eastern and northeastern counties to determine the penetration of natural gas heating in these areas.

---

[44] Skipping Stone located no SCE&G gas-service in these codes after sampling four to six disparate areas within each code using the SCE&G gas availability tool: https://www.sceg.com/for-my-home/start-my-service/gas-availability.

[45] The 32 zip codes with gas service have a total area of 3,291 mi^2 and have ~342,000 postal locations. The 67 zip codes with no gas service have a total area of 5,788 mi^2 and have ~244,000 postal locations.

[46] http://www.energy.sc.gov/files/view/SC%20Natural%20Gas%20Infrastructure%202nd%20DRAFT%203-28-16.pdf at 12.

[47] There are 640 acres in a square mile.

Table 1: 2016 countywide penetration of natural gas heating versus other heating sources

Geography	Occupied housing units; Estimate; Occupied housing units	Occupied housing units; Estimate; HOUSE HEATING FUEL - Utility gas (pctg)	Gas Penetration	Occupied housing units; Estimate; HOUSE HEATING FUEL - Bottled, tank, or LP gas (pctg)	Propane Penetration	Occupied housing units; Estimate; HOUSE HEATING FUEL - Fuel oil, kerosene, etc. (pctg)	Fuel Oil Penetration	Occupied housing units; Estimate; HOUSE HEATING FUEL - Electricity (pctg)	Electricity Penetration
Berkeley County, South Carolina	70,482	12.1%	8,528	2.1%	1,480	0.5%	352	84.3%	59,416
Chesterfield County, South Carolina	18,172	8.9%	1,617	8.6%	1,563	2.2%	400	77.2%	14,029
Clarendon County, South Carolina	13,282	1.5%	199	10.3%	1,368	2.5%	332	83.7%	11,117
Darlington County, South Carolina	26,407	7.7%	2,033	6.6%	1,743	2.2%	581	81.4%	21,495
Dillon County, South Carolina	11,133	6.2%	690	10.2%	1,136	2.7%	301	79.2%	8,817
Florence County, South Carolina	51,749	11.1%	5,744	5.2%	2,691	1.1%	569	81.6%	42,227
Georgetown County, South Carolina	24,379	6.5%	1,585	2.9%	707	1.0%	244	88.4%	21,551
Horry County, South Carolina	122,125	3.6%	4,397	2.7%	3,297	0.4%	489	92.6%	113,088
Lee County, South Carolina	6,400	6.6%	422	9.8%	627	2.0%	128	79.3%	5,075
Marion County, South Carolina	12,090	7.5%	907	8.6%	1,040	1.9%	230	81.3%	9,829
Sumter County, South Carolina	40,815	9.6%	3,918	4.8%	1,959	1.7%	694	82.3%	33,591
Williamsburg County, South Carolina	12,035	4.0%	481	11.1%	1,336	2.7%	325	80.4%	9,676
Totals	409,069	7.5%	30,523	4.6%	18,947	1.1%	4,644	85.5%	349,912

Overall penetration of natural gas for heating is very low across all 12 counties. In addition, oil and propane penetration in these underserviced counties is very low—in the 2-10% range (about 5% on average) range, compared to an electric heat penetration average of 86%.

Based on the population density and natural gas heating penetration in underserviced areas, SCE&G is extremely unlikely to find it profitable to run miles and miles of new natural gas lines to capture new services in these areas. The penetration of electric heating is too high and the population density is too low.

Electric heating penetration poses a significant challenge to gas service expansion because it makes it less economical for households and businesses to take natural gas service once the local distribution lines have been extended. If a gas main line is extended into a new area, it does not mean potential customers there will take the service. Oil and propane users often switch to natural gas when their existing heating system needs to be replaced, and occasionally switch to realize cost savings.[48] It is much more expensive for electric heating users to switch to natural gas. Electric resistance heating installations (i.e., heating with baseboard or floor units) are not conducive to gas conversion absent very pervasive ducting or plumbing work throughout the structure. Even where forced hot air heat pumps are installed, adding a natural gas-fired supplemental firing unit costs about $2,400 on average (not including the cost to run a gas line from the street to the house). This expense is justified only where there are savings over time—which is unlikely unless the cost savings per unit of gas versus electricity is high and the frequency and severity of cold spells that would trigger the natural gas fired supplement to an

[48] An oil-fired forced hot air furnace can be retrofitted with a gas burner. Boilers usually must be completely replaced when the fuel is changed. Conversions before replacement is necessary have been observed in the northeast, where oil and propane penetrations dominate in the areas where gas service has not historically been available.

existing heat pump installation are high as well.[49] Given the high electric heating penetration in underserviced areas of South Carolina and the economic challenges of penetrating that market, local distribution companies are unlikely to invest in service extensions into those areas absent substantial long-term incentives or revenue guarantees.

Low population density also poses a significant challenge to gas service expansion because it limits the number of potential services per mile of distribution main. Even with a 25% penetration rate—the rate in SCE&G's more penetrated areas (i.e., not the 12 counties identified above)—the services per mile would still be so small in the un/underserviced 12 counties that typical profitability would be elusive.[50] Similarly, there is likely insufficient industrial activity and associated industrial demand for natural gas to make extension of service into these rural areas cost-effective and profitable.

For all of these reasons, is most likely that service extension within South Carolina faces economic challenges unrelated to availability of sufficient natural gas transportation to South Carolina.

In-State Pipeline Expansion is Also Not Inhibited by Lack of Interstate Pipeline Capacity

The conclusion that expansion of natural gas infrastructure to underserviced areas of South Carolina is unrelated to availability of sufficient natural gas service into the state also holds true for in-state interstate pipeline expansion, as is independently borne out in slides prepared by DCGT in 2009 and 2017.

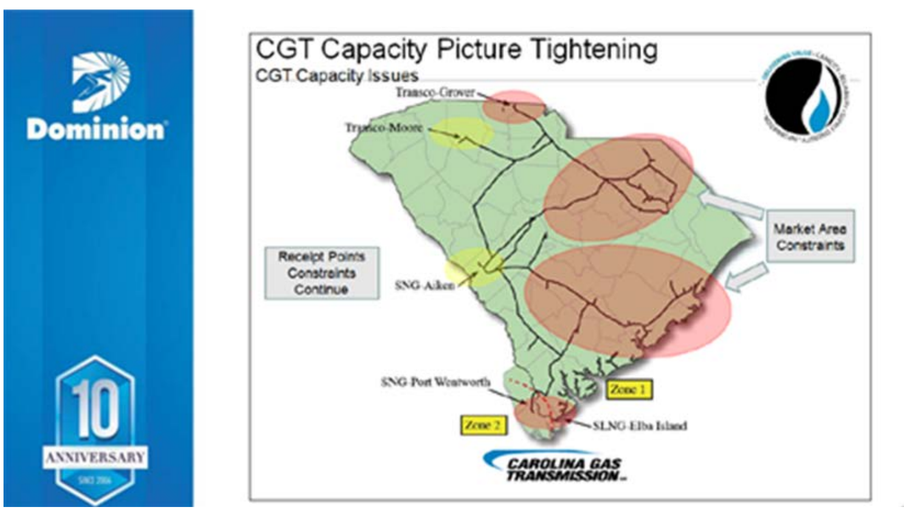


Figure 13: 2009 presentation slide depicting areas of system constraints

[49] It is especially difficult to make the economics of a switch to natural gas work when twelve months of fixed monthly customer charges are spread over a limited number of months (and possibly days) of heating use.

[50] The only way to make the extension profitable would be to raise rates for all gas customers to cover the costs of the otherwise uneconomic extensions.

In 2009, DCGT stated that its system was “tightening” at receipt points into its system and at delivery points in certain market areas. Receipt point constraints relate to DCGT’s ability to receive gas into its system due to limitations on their side of the interconnect with the delivering pipeline. Market area constraints relate to DCGT’s ability to deliver the gas it can receive at its receipt points to certain delivery points. By 2017, DCGT stated that it had to make modifications at its receipt points to receive more gas and at segments of its system between receipt and delivery locations to deliver the received gas.

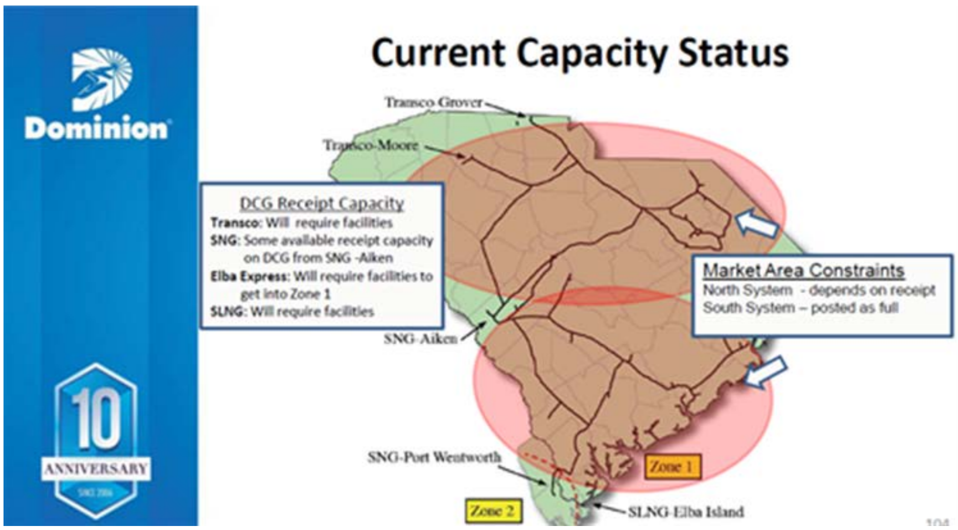


Figure 14: 2017 presentation slide depicting areas of system constraints

The 2009 and 2017 slides both indicate that constraints are on DCGT’s system within South Carolina, not to its system from outside the state. In-state facilities at the South Carolina receipt locations of DCGT are required to receive additional gas into the DCGT system.

This on-system DCGT constraint fact is further borne out by another slide in the 2017 presentation.

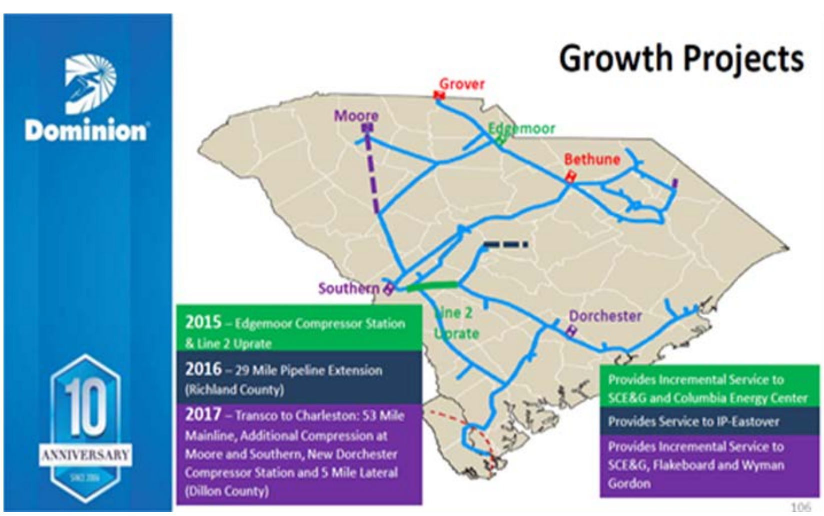


Figure 15: 2017 presentation slide of projects to increase receipt capacity and enable increased delivery service

The 2015 project cites compression on the receipt line from Transco at the Grover receipt point plus a DCGT line uprate to enable incremental service to SCE&G and the Columbia Energy Center. Likewise, the 2016 project cites that a line to International Paper will enable service to that location. Finally, the 2017 project indicates that an additional 53-mile line connecting (and enabling additional receipts from) Transco at Moore to be delivered to SCE&G, Flakeboard, and Wyman Gordon.

Again, these slides and the fact that none of these expansions resulted in the DCGT shipper taking on the same level of expansion on either of SONAT or Transco[51] as represented by their DCGT contract, indicates that subscriptions to service on DCGT (as well as on SONAT or Transco) are independent decisions. Available evidence indicates that they are in no way co-dependent decisions.

Conclusion

If there are natural gas capacity constraints affecting expanded or extended natural gas service in South Carolina, *the constraints are within the State of South Carolina not to the state*. To solve these constraint issues, shippers desiring (or requiring) year-round firm natural gas service will have to subscribe to: one or more expansions of DCGT's ability to receive gas at receipt points, extensions of DCGT's to bring gas to the desired service location(s), and/or an arrangement with SCE&G to extend and reinforce its system to bring gas service to the desired location(s).

[51] SCE&G did subscribe to 40,000 Dthd of capacity on Transco from Transco's Zone 6 (the Marcellus region) to Transco's Zone 4A (in Alabama and enabling deliveries to pipelines serving Florida) that became effective on January 5, 2016. In December 2015, an 18,498 Dthd contract on DCGT with receipts at Transco Grover to SCE&G's Columbia area went into effect.

Appendix A: DCGT Contracted Capacity and Other 2006 to 2016 Metrics

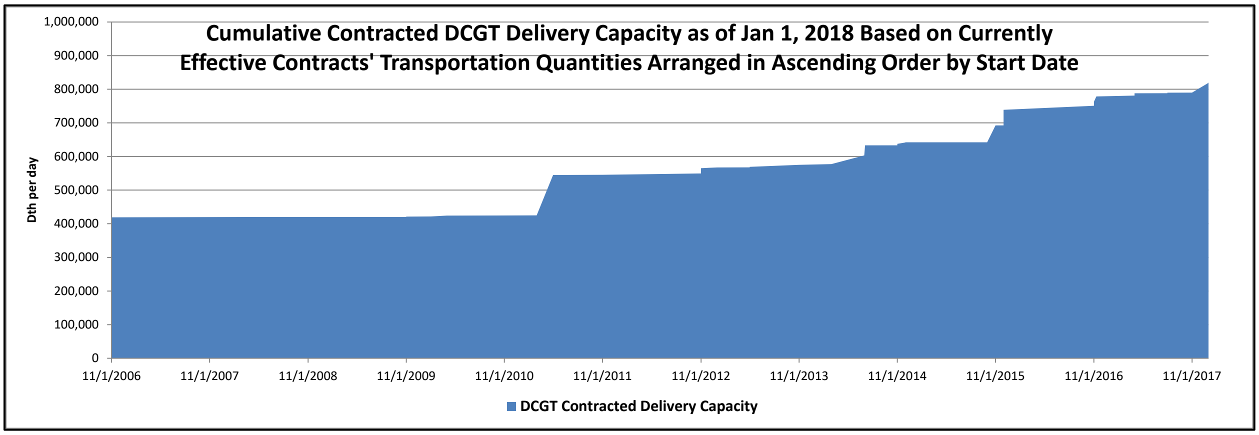
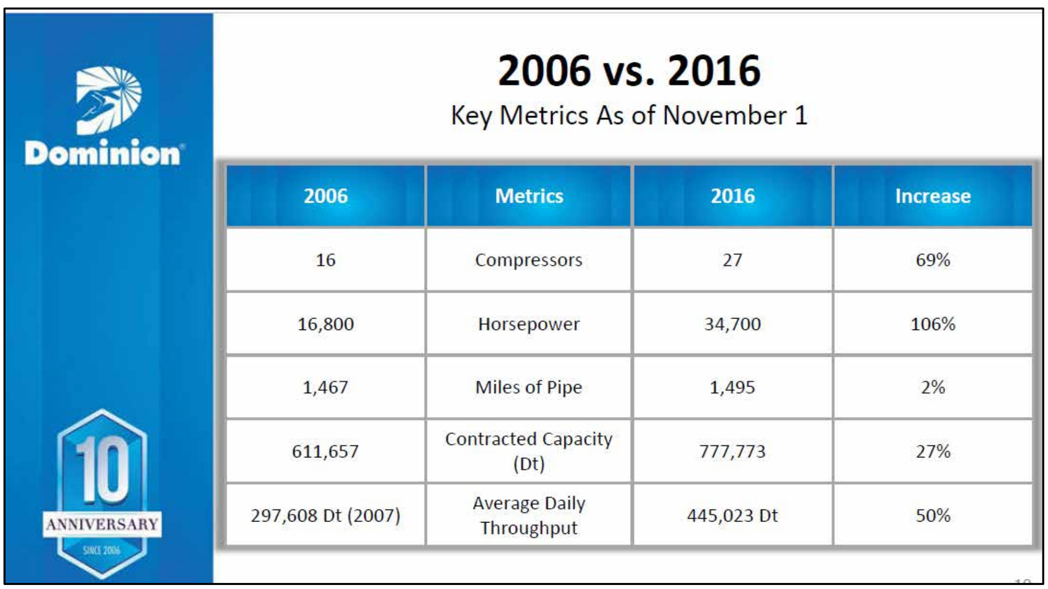


Figure A1. Cumulative contracted DCGT delivery capacity as of January 1, 2018 based on currently-effective contracts' transportation quantities arranged in ascending order by start date

While Figure A1 indicates that in November of 2006 DCGT had only about 400,000 Dthd contracted, it likely had closer to about 611,000 Dthd contracted (see Figure A2 below). Figure A1 does not show the approximately 200,000 Dthd of contracts that were effective in November 2006 and later replaced with other contracts between 2006 and today.[52]



2006	Metrics	2016	Increase
16	Compressors	27	69%
16,800	Horsepower	34,700	106%
1,467	Miles of Pipe	1,495	2%
611,657	Contracted Capacity (Dt)	777,773	27%
297,608 Dt (2007)	Average Daily Throughput	445,023 Dt	50%

Figure A2. DCGT slide on key metrics from 2006 to 2016[53]

[52] The effective dates in the January 1, 2018 postings are the effective dates of the contracts. Some of the later-dated contracts could be reformations of earlier contracts or replacement contracts using capacity that existed prior to the current effective date of the contracts.

[53] This slide was prepared by DCGT for a 2017 presentation to its customers in which it reviewed the prior ten gas years (November 2006 to November 2016).

Appendix B: SONAT Contracted Capacity and Scheduled Flow Data

Figure B1 displays the SONAT contracted capacity along the Far Eastern segment, as well as scheduled deliveries (i.e., daily utilization) along that segment.[54] This Figure aggregates all contracted delivery capacity and all scheduled deliveries to provide an overview of pipeline capacity in this region prior to examining the delivery points most relevant for understanding SCE&G's capacity situation.

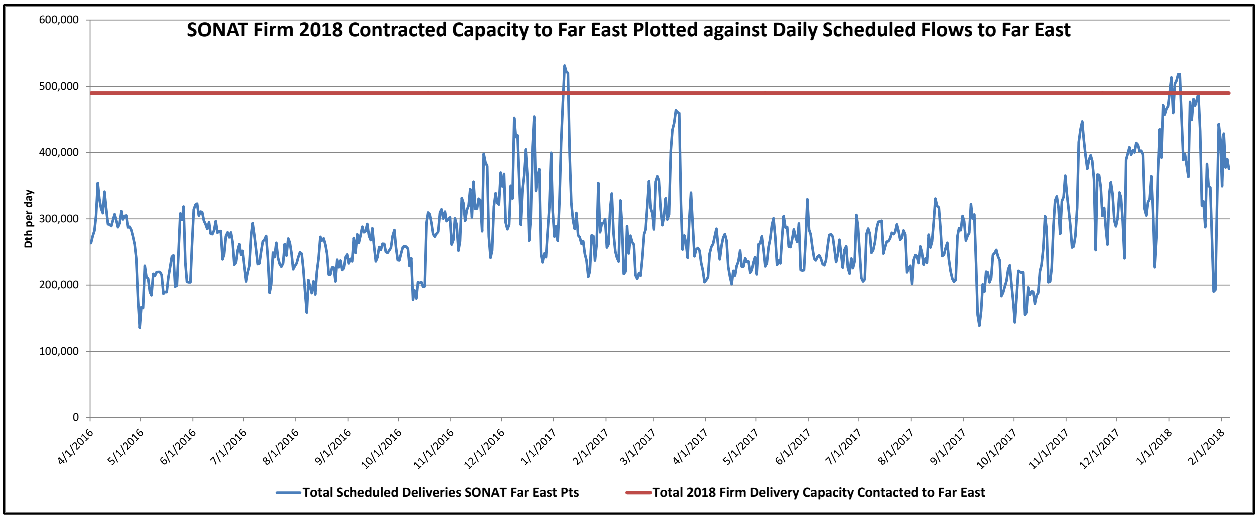


Figure B1: SONAT firm 2018 contracted delivery capacity on the Far Eastern segment plotted against daily scheduled flows, April 2016 through January 2018

SONAT rarely flows (schedules) more than its contracted firm capacity on this Far Eastern segment—a clear indication that the line is not only fully subscribed, but that there is little operationally available capacity in excess of contracted capacity.

Flows to individual locations along this segment of SONAT relative to those locations' contracted firm delivery capacity are presented in Figure B2 and Figure B3 below. Figure B2 presents the contracted firm SONAT capacity (of shippers on SONAT) to DCGT and the scheduled flows to DCGT. DCGT receives gas from SONAT at the terminus of the Far Eastern segment.

[54] At present, there are no listed "receipt points" into SONAT on this Far Eastern segment.

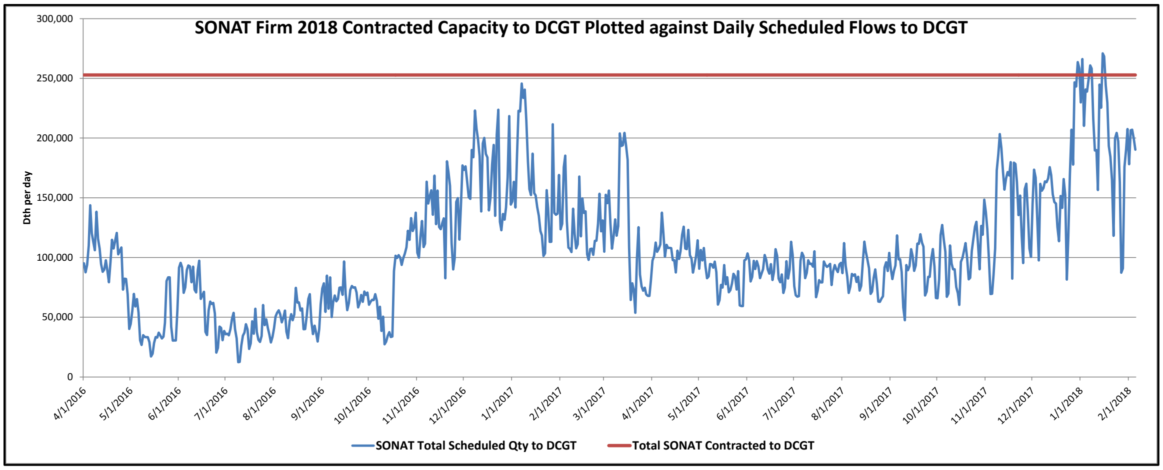


Figure B2: SONAT firm 2018 contracted delivery capacity to DCGT plotted against daily scheduled flows to DCGT, April 2016 through January 2018

Again, as with the picture presented in Figure B1, seldom has SONAT flowed (scheduled) more than its contracted firm capacity to DCGT. This is another clear indication that the line is not only fully subscribed, but that, in the aggregate, there is little operationally available capacity in excess of contracted capacity. DCGT is not a shipper with capacity on SONAT.[55] 96% of SONAT's firm capacity to DCGT is held by local distribution companies, municipal gas distributors, industrial end-users, and government entities; only 4% is held by marketing entities.

Figure B3 presents deliveries to SCE&G's Urquhart power plant and other SCE&G loads located off of the SONAT Far Eastern segment in Aiken County, South Carolina.

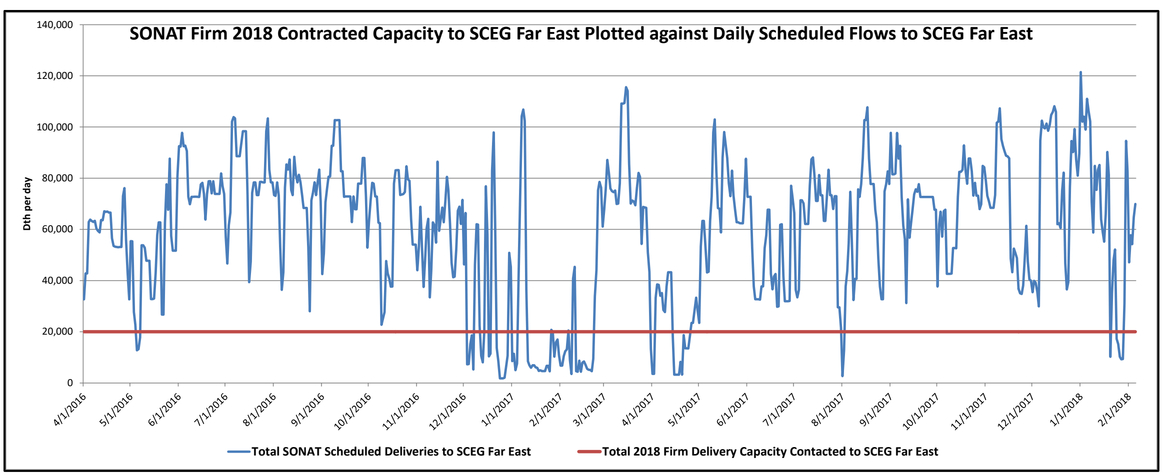


Figure B3: SONAT firm contracted capacity to SCE&G location on SONAT's Far Eastern segment plotted against daily scheduled flows to the SCE&G location

55 Pipelines are rarely shippers on other pipelines. The exception to this general statement is when pipeline A contracts with pipeline B so that A can get gas from one part of its system to another by means of pipeline B, or when pipeline A leases capacity on pipeline B so that A's shippers can seamlessly schedule gas on A that moves through B in order to bring gas to pipeline A's markets.

As can be seen in Figure B3, the flows to the SCE&G location in Aiken County, South Carolina often exceed by 500% to 600% SCE&G's contracted firm to this location. Notably, these flows generally occur outside of the winter periods, which is likely when other shippers are utilizing their firm capacity to make winter deliveries along this segment.

While the scheduled quantities to the SCE&G location in Aiken County, South Carolina as presented above indicate deliveries in excess of firm contracted delivery capacity[56] to the location during non-winter periods, Figure B4 below tells a different story. In Figure B4, Skipping Stone combined the scheduled deliveries to DCGT (Figure B2) with the scheduled deliveries to the SCE&G Aiken County location (Figure B3). SCE&G holds 43% of the delivery capacity on SONAT's Far Eastern segment, including nearly 70% of all delivery capacity to DCGT. Deliveries to either (and both) of these locations consume capacity on the Far East Segment of the SONAT system, and the combination of these two amounts helps clarify the capacity picture for SONAT locations that are particularly important for SCE&G.

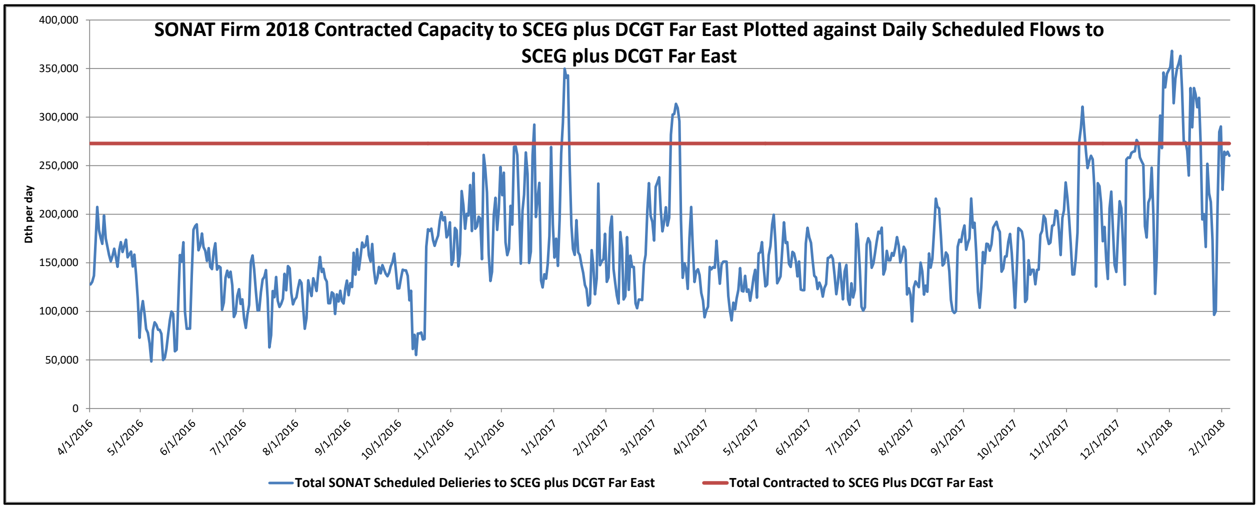


Figure B4: SONAT firm contracted capacity to SCE&G Aiken County location plus firm contracted capacity to DCGT Far Eastern segment plotted against daily scheduled flows to both locations

In Figure B4, the sum of flows to the two locations exceeds contracted firm delivery capacity, often by more than 50,000 Dthd or 20% of contracted firm capacity. Exceedances occur predominantly during the winter-time. While deliveries to the Far East segment of SONAT seldom exceed contracted firm delivery capacity, deliveries to these two locations taken together often do. Whether such deliveries are made by capacity holders on the SONAT Far Eastern segment to locations other than their primary locations (i.e., on a secondary basis), are made by means of contract overruns by holders of capacity to the subject locations, or are made by means of interruptible contract capacity is not known. Whatever the reason, it is clear that the level of demand being expressed at these two locations is greater than the contracted firm

---

[56] The scheduled quantity data obtained from pipelines does not give any information as to the shippers or contracts that are being scheduled to (in the case of deliveries) or from (in the case of receipts) the locations. The gas could be being delivered on a shipper's contract on a secondary basis (i.e., to a location other than their primary point(s) or under an interruptible contract.

delivery capacity on SONAT to these two locations, whether due to price, demand, or a combination of the two. An effect of this may be the perception that the whole SONAT Far Eastern segment of SONAT and the northwestern portion of DCGT, especially as it relates to deliveries to DCGT for onward delivery elsewhere in South Carolina, are constrained.

Appendix C: Transco Contracted Capacity and Scheduled Flow Data

Figure C1 displays Transco 2018 firm contracted capacity to DCGT plotted against scheduled flows on Transco to DCGT.

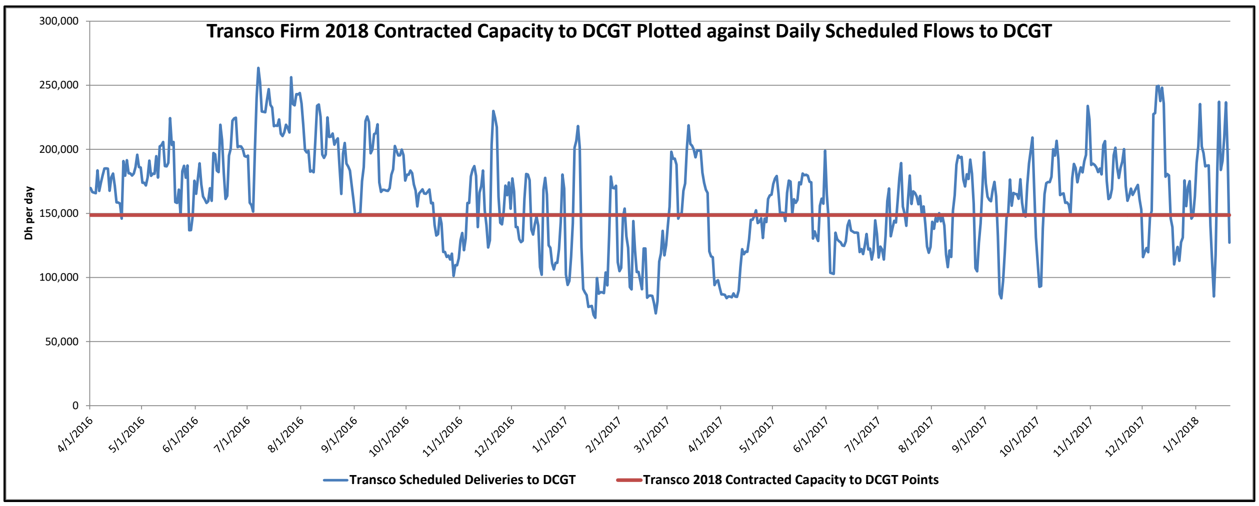


Figure C1: Transco firm 2018 contracted capacity to DCGT plotted against daily scheduled flows to DCGT

The contracted capacity on Transco to DCGT is about 150,000 Dthd.[57] As can be readily seen in Figure C1, Transco's scheduled deliveries to DCGT often exceed Transco's contracted capacity to DCGT points. Thus, Transco delivers substantially more gas to DCGT than shippers on Transco[58] have contracted capacity to deliver to DCGT on a primary basis. Deliveries to DCGT from Transco routinely throughout the year exceed the contracted capacity amount by 50,000 Dthd (about 30%), and often by 100,000 Dthd (about 60%).

In Figure C2, below, Skipping Stone presents all 2018 contracted Transco delivery capacity to all South Carolina points and plots that against scheduled flows to all South Carolina locations off of Transco.

---

[57] This compares to about 268,000 Dthd contracted on SONAT to DCGT. The total contracted firm delivery capacity directly to DCGT between SONAT and Transco is about 420,000 Dthd. This compares to nearly 900,000 Dthd contracted on DCGT as of mid-2018.

[58] As with SONAT, DCGT is not a shipper on Transco.

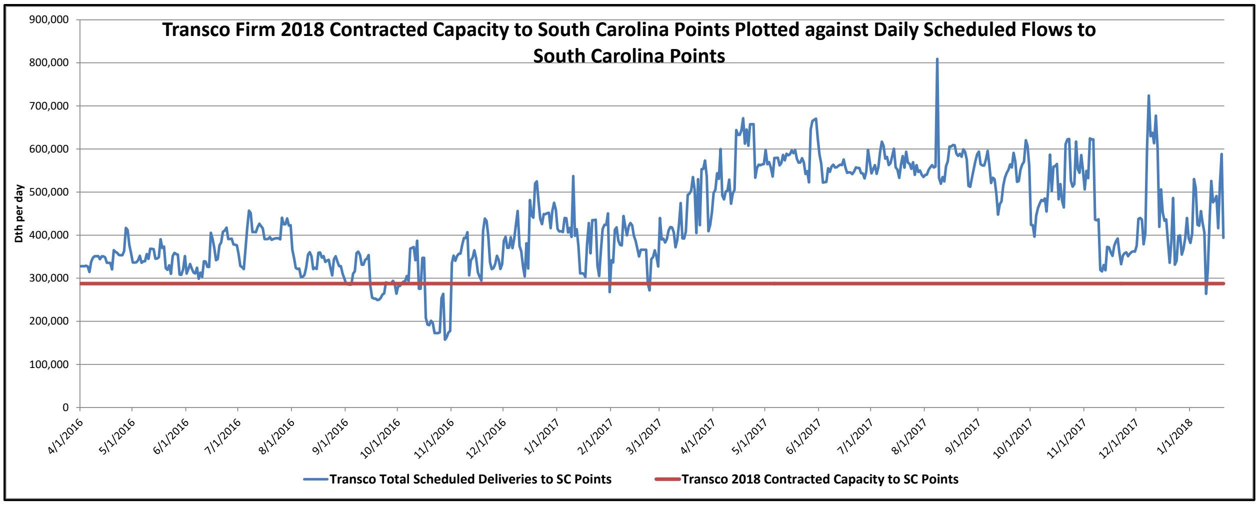


Figure C2: Transco firm 2018 contracted delivery capacity to South Carolina points plotted against daily scheduled flows to South Carolina points

As was seen in Figure C1, Figure C2 shows that the quantities of gas delivered by Transco to South Carolina points usually exceed, and often greatly exceed, contracted firm quantities to South Carolina points. In fact, deliveries to South Carolina locations peaked at 500,000 Dthd (0.5 Bcfd) higher than contracted and were routinely twice the amount of contracted firm capacity (i.e., 300,000 Dthd in excess of about 300,000 Dthd of contracted capacity). At first blush this appears to be a very large quantity of delivered gas in excess of firm capacity. However, Figure C3 puts this quantity in perspective as it relates to the full Transco capacity available to South Carolina.

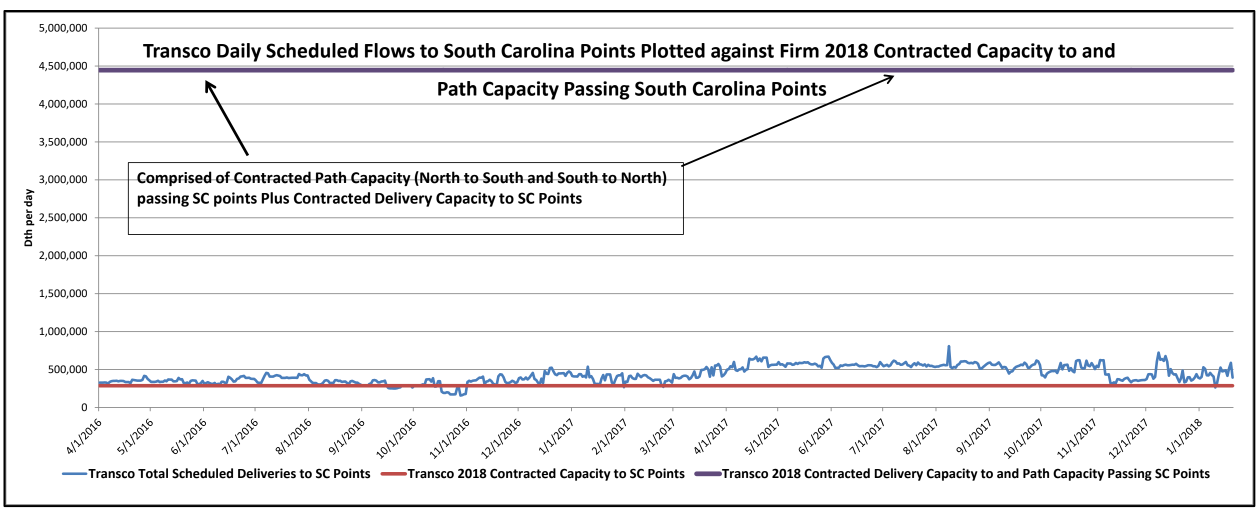


Figure C3: Transco daily scheduled flows to South Carolina points plotted against firm contracted capacity to and path capacity passing South Carolina points

Figure C3 plots the same data presented in Figure C2, but plots it on the scale of capacity available to serve all South Carolina points. In other words, it shows the path capacity: (north to south and south to north) passing South Carolina points as well as the contracted delivery capacity to South Carolina points. As can readily be seen, although firm contracted capacity to South Carolina (or DCGT) on Transco is much too small to accommodate daily deliveries and this makes it appear that South Carolina faces constraints (owing to subscribed firm versus demand), South Carolina is actually in a great position with regard to Transco and South Carolina demands.

To ensure that Figure C3 does not misrepresent South Carolina's position in Transco Zone 5 (the Zone covering South Carolina, North Carolina, and Virginia) and does not miss other demands in Zone 5 that would alter the amount of total subscribed capacity available, Skipping Stone also plotted the balance of deliveries to all Zone 5 locations against available capacity into and through Zone 5. This analysis is presented below in Figure C4.

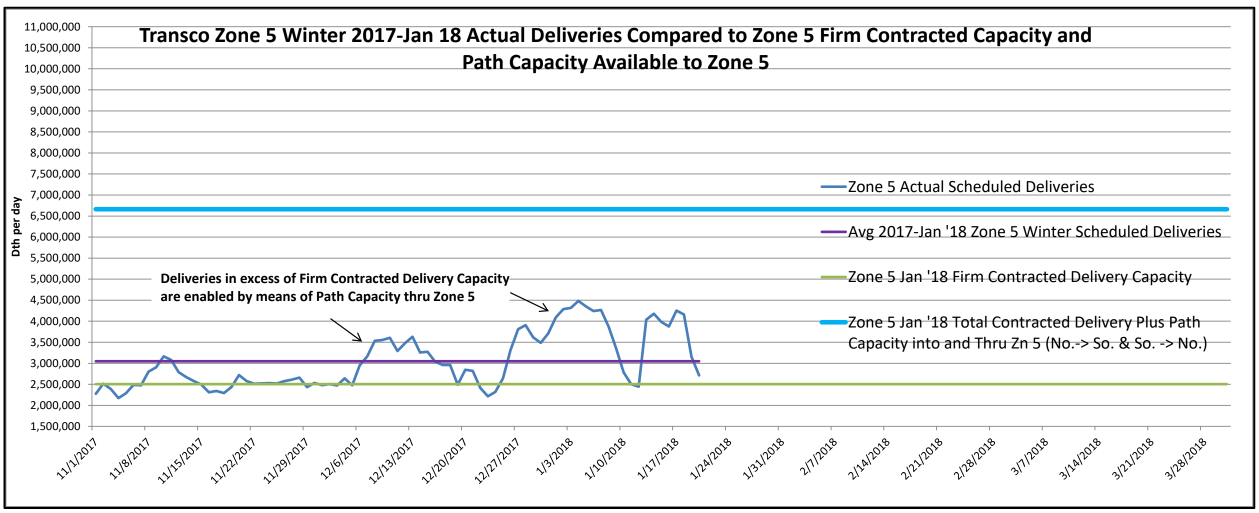


Figure C4: Transco Zone 5 winter 2017 through January 2018 actual deliveries compared to Zone 5 firm contracted capacity and path capacity available to Zone 5

In Figure C4, the green horizontal line represents the total subscribed Transco delivery capacity to points in Zone 5. There is about 2.5 Bcfd of subscribed Transco delivery capacity at these points (inclusive of South Carolina's approximately 0.29 Bcfd of firm delivery point capacity). The purple horizontal line represents the average deliveries per day of about 3.0 Bcfd; the squiggly blue line presents the daily scheduled flows to all Zone 5 points; and the blue horizontal line represents all the path capacity plus delivery point capacity in Zone 5. Figure C4 shows that there was excess available capacity in Zone 5 this winter. Even during the "bomb cyclone" event in early January when actual deliveries reached 4.5 Bcfd, there was still another 2.0 Bcfd of available capacity.

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF VIRGINIA ELECTRIC AND POWER COMPANY	)	
	)	Case No. PUR-2018-00065
In re: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et. seq.	)	

Direct Testimony of

Gregory M. Lander

On Behalf of

Environmental Respondents

August 10, 2018

<u>Summary of Testimony of Gregory M. Lander</u>

My name is Gregory M. Lander. I am head of Skipping Stone, Inc.'s Energy Logistics practice. The purpose of my testimony today is to describe two areas of missing or inadequate analysis in the Company's 2018 IRP that relate to the IRP's consideration of costs of the Atlantic Coast Pipeline and raise significant concerns about whether the Company has, in fact, identified a reasonable least-cost generation scenario. First, I will testify that the Company did not study or present an analysis of the cause, frequency, duration or magnitude of natural gas price spikes. Analyzing four scenarios for forward-looking basis projections between different pricing locations, I calculated the **<u>avoidable</u>**, **<u>net cost</u>** to Company ratepayers of new pipeline capacity like the Atlantic Coast Pipeline to be as high as $3 billion over the next 20 years. The second area of missing or incomplete analysis that my testimony will address is that the Company has not performed a comparative analysis of all-in fuel cost, as it should be required to do as part of the least-cost planning exercise of the 2018 IRP. The load factor of a short-term peak caused by extreme winter weather is so low that meeting such demands with gas-fired only units, which require costly long-term pipeline capacity, is not prudent.

The Company's 2018 IRP embeds the costs of the Atlantic Coast Pipeline into each of the generation scenarios it presents. In essence, the IRP asks the Commission to accept that the Atlantic Coast Pipeline is built and that ratepayers should pay for it without ever explaining to the Commission what those costs are and why they are justified in a least-cost planning exercise. Absent comparative analysis of viable alternative fueling logistics and their respective associated all-in costs that would be the product of these analyses, it is unlikely in the extreme that the Company's IRP has achieved the objective of identifying a reasonable, least-cost generation scenario.

Q. Please state your name and address.

A. My name is Gregory M. Lander. My business address is 83 Pine Street, Suite 101, West Peabody, MA 01960, and my email address is glander@skippingstone.com.

Q. What is the purpose of your testimony?

A. The purpose of my testimony today is to describe two areas of missing or inadequate analysis in the Company's 2018 IRP that relate to the IRP's consideration of costs of the Atlantic Coast Pipeline and raise significant concerns about whether the Company has, in fact, identified a reasonable least-cost generation scenario. First, I will testify that the Company did not study or present an analysis of the cause, frequency, duration or magnitude of natural gas price spikes and did not assess what infrastructure developments are already underway and under development that could reduce, if not eliminate, the frequency, duration, and magnitude of such price spikes. Analyzing four scenarios for forward-looking basis projections between different pricing locations, I calculated the **avoidable**, **net cost** to Company ratepayers of new pipeline capacity like the Atlantic Coast Pipeline to be as high as $3 billion over the next 20 years. I corroborated my analysis using natural gas price data provided by the Company, which showed a net cost to Company ratepayers of the Atlantic Coast Pipeline to be $2.5 billion over the next twenty years when compared to the costs of using existing infrastructure. In sum, Company ratepayers will experience no net value from paying for the path connecting Dominion South Point to Transco Zone 5 as the Atlantic Coast Pipeline would. Additionally, because the IRP does not include the price spike analysis that I recommend in my testimony, it does not present reasonable, least-cost generation scenarios.

Q. What is the second area of missing or incomplete analysis that your testimony will cover?

A. The second area of missing or incomplete analysis that my testimony will address is that the Company has not performed a comparative analysis of all-in fuel cost, as it should be required to do as part of the least-cost planning exercise of the 2018 IRP. Had the Company analyzed its load serving requirements with demand duration curves as part of its least-cost planning, it would see that the load factor of a short-term peak caused by extreme winter weather is so low that meeting such demands with gas-fired only units is not prudent from a fixed-cost incurrence perspective. Multiple options, such as building dual fuel CTs or purchasing energy from PJM, can satisfy a short-term winter peak, should one occur, without burdening ratepayers with the high fixed costs of new gas pipeline capacity.

Q. Based on your analyses, what are your overall conclusions regarding the Company's 2018 IRP?

A. The Company's 2018 IRP embeds the costs of the Atlantic Coast Pipeline into each of the generation scenarios it presents. However, the Company does not quantify these costs or justify them anywhere in the IRP; it has not properly costed–out the all-in cost of increasing, beyond its current pipeline capacity portfolio, the costs associated with the level of pipeline capacity it intends to obtain on the Atlantic Coast Pipeline. In essence, the IRP asks the Commission to accept that the Atlantic Coast Pipeline is built and that ratepayers should pay for it without ever explaining to the Commission what those costs are and why they are justified in a least-cost planning exercise. My analysis demonstrates that an analysis of price spike information and an analysis of load duration curves could significantly improve the IRP's function as a tool intended to identify the least-cost generation scenario; keeping in mind that least-cost generation measurements should include the costs of associated necessary fuel logistics for generation assets consuming fuel. Absent comparative analysis of viable alternative fueling logistics and their respective associated all-in costs that would be the product of these analyses, it is unlikely in the extreme that the Company's IRP has achieved this objective.

Qualifications

Q. What is your occupation and by whom are you employed?

A. I am President of Skipping Stone, LLC ("Skipping Stone").

Q. What is your educational and professional background?

A. I graduated from Hampshire College in Amherst, Massachusetts, in 1977, with a Bachelor of Arts degree. In 1981, I began my career in the energy business at Citizens Energy Corporation in Boston, Massachusetts ("Citizens Energy"). I became involved in the natural gas business of Citizens Energy in 1983. Between 1983 and 1989, I served as Manager, Vice President, President and Chairman of Citizens Gas Supply Corporation (a subsidiary of Citizens Energy). I started and ran an energy consulting firm, Landmark Associates, from 1989 to 1993, during which time I consulted on numerous pipeline open access matters, a number of Federal Energy Regulatory Commission ("FERC") Order No. 636 rate cases, pipeline certificate cases, fuel supply and gas transportation issues for independent power generation projects, international arbitration cases involving renegotiation of pipeline gas supply contracts, and natural gas market information requirements cases (FERC Order Nos. 587 et seq.). In 1993, I founded TransCapacity LP, a software and natural gas information services company. Since 1994, I have also been a Services Segment board member of the Gas Industry Standards Board ("GISB") and its successor organization, the North American Energy Standards Board ("NAESB"). During the period 1994 to 2002, I served as a Chairman of the Business Practices Subcommittee, the Interpretations Committee, the Triage Committee, and several GISB/NAESB Task Forces. I am currently a Board Member of NAESB and have served continuously in that capacity since 1997. Skipping Stone, Inc. acquired TransCapacity in 1999, and since that time I have headed up Skipping Stone's Energy Logistics practice, where my specialization has been interstate pipeline capacity issues, information, research, pricing, acquisition due diligence and planning. In 2001, Skipping Stone launched CapacityCenter.com, a pipeline capacity information service. In 2004, Skipping Stone was acquired by Commerce Energy Group, a national retail energy services provider. In 2005, I was appointed President of Skipping Stone, which operated as a wholly owned subsidiary of Commerce Energy Group. In 2008, I purchased substantially all of the assets of Skipping Stone and now operate essentially the same business as before the Commerce Energy transaction as Skipping Stone, LLC.

From 1984 to present, I have maintained a deep familiarity with a wide range of pipeline transportation issues, beginning with access to pipeline capacity to make competitive sales, resolution of the pipeline take-or-pay contracting regime, pipeline affiliate marketer concerns, restructuring of the pipelines from merchants to transporters and thereafter, and definitions of what constituted a pipeline capacity "right" for the purposes of formulating the then newly commenced capacity release and capacity rights trading business process. I continue to be involved in nearly all facets of the capacity information and trading business as part of my duties at Skipping Stone. In addition, I have been the lead principal on all 50+ pipeline and storage mergers and acquisitions transactions as well as all pipeline and storage facility expansion projects for which Skipping Stone has been retained by potential purchasers and project sponsors to provide economic due diligence consulting and market analysis.

Q. Have you filed testimony in regulatory proceedings previously?

A. I have filed testimony in several proceedings including FERC Docket No. RP04-251-000, which was an El Paso Natural Gas Company ("EPNG") proceeding regarding pathing and segmentation. In FERC Docket No. RP08-426-000, (also an EPNG proceeding), I sponsored answering and supplemental answering testimony. I also filed testimony in FERC Docket No. RP10-1398, the first fully litigated EPNG Rate case in more than three decades. In addition, I have filed testimony in Massachusetts Department of Public Utilities Case Nos. 13-157, 15-34, 15-48, 15-39; Maine Public Utilities Commission Case No. 2014-00071; Virginia Corporation Commission Case No. PUR-2017-00051; Missouri Public Service Case GR-2017-0215; GR-2017-0216; California Public Utilities Commission Cases 17-10-007 and 17-10-008 (Consolidated) Applications of San Diego Gas & Electric (U902M) and Southern California Gas Company (U 338-E) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019; Virginia Corporation Commission Case No. PUR-2018-00067 Application of Virginia Electric and Power Company to revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia; and California Public Utilities Commission Application No. 17-10-002 Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) Regarding

Feasibility of Incorporating Advanced Meter Data Into the Core Balancing Process.. Please refer to Exhibit ER-01, which contains a full list of case names and docket numbers as well as my current CV.

Q. On whose behalf are you testifying in this proceeding?

A. I am submitting testimony on behalf of the Environmental Respondents.

Q. How is your testimony organized?

A. First, I discuss the frequency, magnitude and duration of price spikes in natural gas market prices, particularly as they occur in Transcontinental Gas Pipe Line Corporation's (Transco's) market areas, as well as their causes and what developments are underway that will address the cause of these observed price spikes. In this regard, I also discuss that while the Company refers to price spikes and volatility in its IRP, it undertakes no quantitative or qualitative analysis of these price spikes or any analysis as to the costs of alternative means of addressing the impacts from such price spikes on Company ratepayers.

Second, I discuss that the Company should have examined its load duration curves and then matched resources – including fuel source – to match to the curves on a least-cost basis. In this regard, I also discuss how very low load factor utilization of resources (generation and associated fuel logistics assets) can greatly impact ratepayer costs depending on the "plan" identified to fuel such resources. The Company appears to have: 1) undertaken no quantitative or qualitative analysis of either load duration or load factor; 2) provided no analysis as to the costs of alternative means of addressing the load duration or low load factor realities they face and will face; nor 3) assessed and presented for review the impacts on ratepayers of the available alternatives.

Q. Are you submitting attachments with your testimony?

A. Yes. They are:

1. Lander 1
2. Lander 2
3. ER 8-11(b)
4. ER 7-3(c)
5. Staff 7-92(a)
6. Staff 3-31 (Attachment Staff Set 3-31 (KS).xlsx)
7. Staff 9-107(f)

Q. Let's begin with your testimony about natural gas price spikes. Are there any forms of analysis that you found missing from the Company's IRP?

A. Yes. I found that in its discussion of price spikes and their impact on Company ratepayers it did not analyze a number of things as part of addressing this situation.

Q. Please elaborate.

A. The Company: (1) did not study nor present any analysis of price spike cause, frequency, duration or magnitude; and (2) did not assess what developments are already underway and under development that might address the fundamental cause of price spikes nor how those developments will impact and reduce, if not eliminate, the frequency, duration, and magnitude of such price spikes. Note that when price spike frequencies, durations and magnitudes are reduced, the relative value (i.e., benefit) relative to associated costs of addressing the remaining estimated frequency, duration and magnitude change and change dramatically. In short, as the value of any "benefit" diminishes while "costs" to achieve that benefit do not, net benefit can vanish and instead yield net cost.

Q. As an initial matter, where are the Company's generation stations located?

A. Transco Zone 5.

Q. Can you provide some background on what causes price spikes to occur in Zone 5, the Zone that the Company's generation stations are located in?

A. Yes. First Zone 5 is one of 6 rate Zones that are present on the Transco system. In addition, while Transco charges the same rates based upon these 6 Zones[1], Transco distinguishes its capacity contracting within Zone 6 into two what I will call sub-zones for capacity pathing purposes, but not for transportation recourse rate purposes.

Q. What are those two sub-zones for capacity pathing purposes?

A. They are Zone 6 NY-PA (commonly referred to as Zone 6 Non-NY in the price publication journals) and Zone 6 NY City (commonly referred to as Zone 6 NY in the price publication journals). The Zone 6 NY-PA Zone for capacity pathing purposes of Transco includes the states of Maryland, Delaware, Pennsylvania and New Jersey, but excluding, in New Jersey, delivery points in the counties of Union and Bergen (counties adjacent to NY) and one location in Middlesex County that is right on the Union County-Middlesex County border. The Transco capacity contracts with Zone 6 NY City-denominated delivery points, for capacity pathing purposes, include the delivery points in the New Jersey counties I just discussed, plus all delivery points in the counties of

---

[1] Transco's rate design is a matrix rate design where shippers pay reservation charges based upon their reserved path quantities from Receipt Zone to Delivery Zone without regard to sub-zone pricing locations which may characterize prices of natural gas delivered to one or more geographical or virtual location(s) within a rate zone.

Richmond, NY (i.e., Staten Island), Kings or New York, NY (i.e., Manhattan), Queens, and Nassau counties of New York state.

Q. Please explain the significance of this specificity of Transco's capacity pathing as it relates to these two sub-zones.

A. The sum of Zone 6 contracted delivery capacity in Zone 6 Non-NY (i.e., Zone 6 NY-PA) and Zone 6 NY City combined is just over 6 Bcfd (6,003,245 Dthd as reported in Transco's April 1, 2018 Index of Customers). However, within that 6 Bcfd of rate Zone 6 capacity, only approximately 2.3 Bcfd (2,273,019 Dthd), or less than 40% of the total, have Zone 6 NY City delivery points. In addition, on August 20, 2018, a total of 1.7 Bcfd of additional capacity through Zones 6 and 5 and to Zone 4 will come into service with the completion Transco's Atlantic Sunrise. Note also that none of Atlantic Sunrise's increase of Transco capacity increases delivery capacity to Zone 6 NY City.

Q. Please explain the significance of these facts.

A. First I have to describe the way that the daily market in Transco Zone 6 operates. Within Zone 6 there is a pooling point available to every shipper with Zone 6 capacity, regardless of whether that capacity is to deliver in Zone 6 Non-NY or Zone 6 NY City. That pooling point is at a virtual location called Station 210. Transco identifies (for capacity pathing purposes) Station 210 as being just east of where the Transco Leidy Line intersects with the main north-south trunk line of Transco in New Jersey. See map below and the Station 210 Circle.

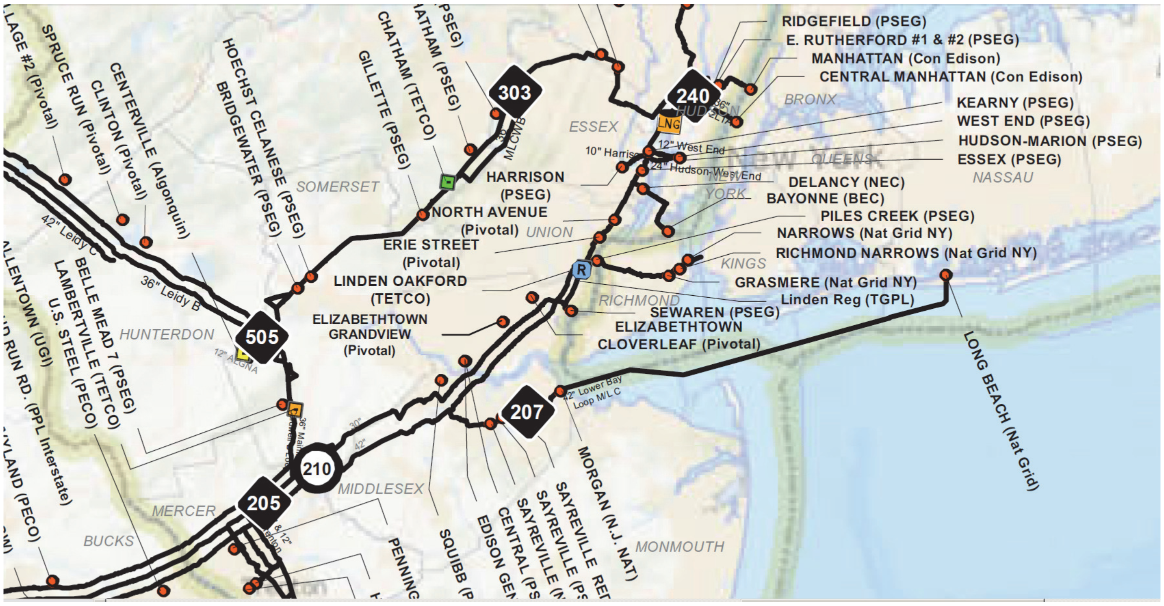


Figure 1

Q. How does Station 210 work?

A. The way a pooling point operates is as follows. Think of the pool as a virtual bucket. Gas on a contract with rate Zone 6 capacity can deliver gas into the shipper's account at the pool. When the gas leaves the transportation contract and goes into the bucket, it loses the transportation agreement identifier, but retains the shipper identifier (i.e., it's the shipper's bucket within the larger Station 210 bucket). Then the shipper can transfer title to gas, from their pool account, to either another shipper's pool account or to a shipper's transportation agreement (either one of their own transportation agreements or that of a different shipper with rate Zone 6 capacity). Generally speaking, the most common transfer is from one shipper's pool account (bucket) to another shipper's pool account (bucket). The importance of this fact is that when shippers with gas delivered into a Station 210 pool account transfer their gas to another shipper's pool account, the selling shipper does not know where the buying shipper will take the gas that the selling shipper just sold.

Q. Please explain why this understanding of how the pool works is important to the discussion of how the Company did not examine the cause, frequency, duration or magnitude of natural gas price spikes.

A. First, let me explain what happens to prices in New York City on a very cold day. New York is a retail access state. This means that much of the load in NY City is served by marketers and not by the ConEd or the National Grid (Brooklyn Union Gas or BUG) local distribution companies (LDCs). Under the retail access rules, ConEd and BUG impose penalties on marketers on any very cold day to the extent the marketer fails to deliver enough gas to cover the loads of their customers. The penalty that they will impose is a charge equal to the journal published daily price ***plus*** $10.00 Per Dth.

Q. What is the effect of this penalty on the Station 210 pool?

A. The effect of this $10.00 above highest price in the market penalty level is that on days when not enough pipeline gas can get into New York City, the marketers and suppliers with gas at Station 210 want the highest price for their sales. They act this way because they know they can get this price from those wanting to avoid paying $10.00 more than that highest price. Now, here is where the operation of the pool comes into play. Because, as I said above, the sellers don't know if their gas is going to try to get into New York City, or might be flipped from their buyer to a shipper wanting to go into New York City. For that reason, the sellers with gas in their Station 210 bucket all charge the same price-spiked price.

Q. OK, that explains what's going on at the Station 210 pool, but how does that impact gas prices in Zone 5 where the Company accesses gas to run its generation facilities?

A. Well, Zone 5 also has a pool. That pool is Station 165. Station 165 operates the same way that Station 210 operates. Moreover, shippers with capacity that can get to Zone 6 from Zones 3, 4 and/or 5 can insist on getting the same, or nearly the same price as the Station 210 price, for gas they can instead sell at Zone 5's Station 165[2]. Thus, because their gas; that they can put into the Station 210 pool, could instead be put into the Zone 5 pool, they will sell at the Zone 5 pool at Station 165 only if they can get the same or nearly the same price as that available to them at the Zone 6 pool at Station 210. Likewise, because shippers with capacity that can get gas to Zones 4 or 5 from Zone 6 (i.e., from the Leidy line and the Marcellus producing region) can also sell into the Zone 6 pool or the Zone 5 pool, they too insist on getting the same high price without regard to which pool they sell at. Finally, these prices spikes in Zone 5 and Zone 6 happen because not enough gas can actually get into New York City on the very coldest days.

Q. How frequent are the price spikes that you have described occurring because not enough gas can actually get into New York City?

A. Not that frequent. For these purposes I define a price spike as greater than \$35.00 per Dth, or greater than the Dth equivalent of \$4.00 per gallon of No. 2 oil (diesel). I picked this threshold because at that price, given the higher heat rate of generating electricity from fuel oil versus natural gas (~13.5 Dth/MW vs. 11.2 Dth/MW) means that a \$4.00 gallon of oil turns into a \$4.82 per gallon for the usable Dth[3]. Thus at \$35.00 gas, fuel switching between natural gas and diesel for combustion turbines can come into play

[3] Diesel fuel oil has 138,600 Btu/gallon; thus requiring 7.21 gallons to equal 1 MMBtu (1 Dth). \$4.00/gallon times 7.21 equals \$28.86/Dth. Combustion Turbine diesel versus natural gas heat rate adjusted \$28.86 becomes ~\$34.78/Dth.

even in extreme diesel price situations. In the chart below I show the frequency of price spikes in Zone 6 Non-NY since August 2004 through June 30th, 2018.

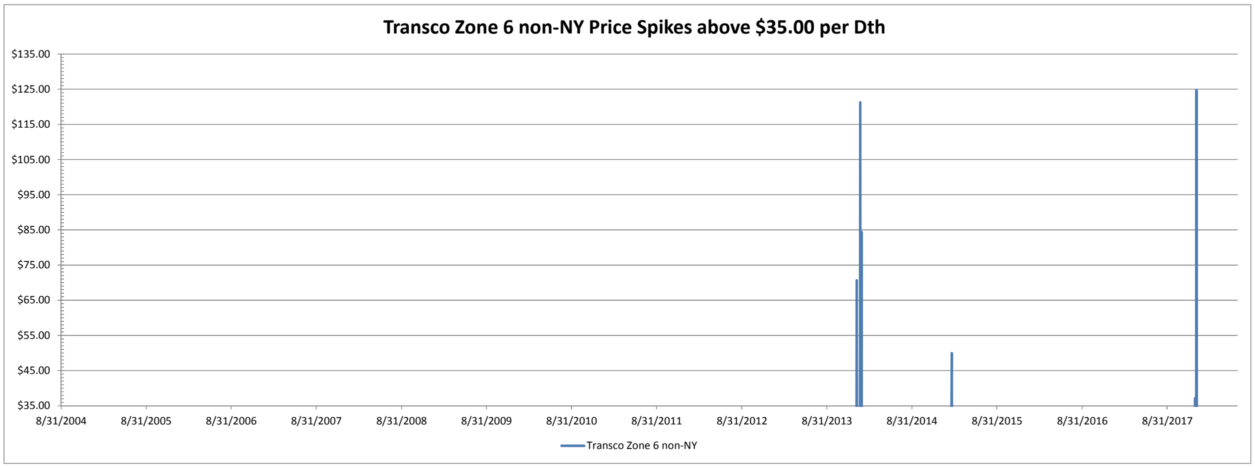


Chart 1

As can be seen in the chart above, there have been 5 separate price spikes over the 13 years and 10 months covered by the chart. The 13 years and 10 months is how long Zone 5 prices have been published by Natural Gas Intelligence (NGI).

Q. What does that tell you?

A. It tells me the price spikes in Zone 5 and Zone 6 are infrequent.

Q. What about their duration and magnitude?

A. With respect to duration, one price spike continued for 7 days, one for 4 days, two were for 2 days and one was for 1 day. In total there were only 16 days in the 13 years and 10 months in which Zone 5 and Zone 6 experienced a price spike above $35.00 per Dth. With respect to magnitude, averaging the daily price for each of the 5 price spike periods, the highest average magnitude over the consecutive days was $86.59 which was for the 2-day price spike this past winter. Over the 16 days total duration, the average cost per Dth was $68.26. The durations in some cases persisted over weekends and my calculations take account of that. In the 13 years and 10 months there were 5,052 days.

This means that less than 0.33% of the time prices in Zone 6 Non-NY spiked. If one only looked at the period between the first spike (January 6, 2014) and June 30, 2018, that extent of time was 1,636 days. Over this shorter period, prices spiked only 1% of the time.

Q. Can adding more capacity and/or gas to either or both of Zones 6 or 5 address these spikes?

A. No, adding capacity or gas to either of these zones will not address spikes caused by New York City constraints—that is constraints between Station 210 and the boroughs of New York City.

Q. Is there any infrastructure or other changes that can address the constraints between Station 210 and the boroughs of New York City?

A. Yes, and just such a project is slated for completion and in-service for the winter of 2019/2020 (the winter after the coming one). Transco's Northeast Supply Enhancement project, a.k.a NESE, will increase capacity into New York City by 400,000 Dthd.

Q. Will the NESE help alleviate the New York City driven price spikes in Zone 5 and Zone 6?

A. Yes.

Q. Please explain why.

A. There are two pipelines that deliver into the boroughs of New York City and to the pricing location known as Zone 6 NY. They are Texas Eastern Transmission (TETCO) and Transco. TETCO can deliver 1.9 Bcfd (1,904,468 Dthd). Transco can deliver the 2.27 Bcfd discussed above. The total of these two is just over 4.1 Bcfd (4,177,487 Dthd). The 400,000 Dthd of additional capacity created by the NESE project increases total NY

City pipeline delivery capacity to 4,577,487 Dthd, an increase of 9.6%. This is also an increase of Transco's New York City delivery capacity of 17.6%. This latter number is the more significant for Transco Zone 5 and Zone 6 non-NY pricing because 17.6% more Transco demand can be served from Station 210, which is the origin point for the NESE capacity. In other words, the increased capacity created by NESE will mean fewer days in which gas deliveries into New York City are constrained.

Q. Is it your conclusion then that the NESE project will have an impact on the frequency, duration and magnitude of potential future price spikes?

A. Yes. The NESE project will certainly reduce duration and with that the average magnitude (which is directly related to duration) of price spikes, and it certainly won't increase, and will likely decrease, their frequency.

Q. So, if we ignore the effect of the NESE project and prices continue to only spike one percent of the time, as you've shown has been the pattern since 2014, are there ways the Company can avoid the impacts of those spikes on ratepayers?

A. Yes, when it comes to an electric generator avoiding those spikes, the generator can generate electricity with back-up dual fuel (i.e., diesel), or it can buy pipeline capacity connecting their generators to a supply area receipt location. The choice between these two options, should, in my opinion, be made on the basis of least-cost.

Q. Did you do any comparative analysis between these two options as they would affect the Company?

A. Yes. I provide that analysis below when I discuss Company load factors and appropriate planning based upon load duration analysis and associated load factors.

Q. OK, my next questions focus on the second option you mention, purchasing new pipeline capacity. What are the options if the Company wanted to get cheaper gas than Zone 5 gas is currently priced?

A. Prices in Zone 5 will change as new pipeline capacity into Zone 5 becomes operational. Specifically, the Atlantic Sunrise and its additional 1.7 Bcfd of capacity into Zones 6, 5 and 4 in 2018 will have a depressing effect on Zone 5 prices during all periods of the year, except the 1% price spike periods.

Q. Please explain.

A. As a result of the Atlantic Sunrise project, more gas will be available to be traded at the Zone 6 and 5 pools. And, because Atlantic Sunrise reaches all the way down to Zone 4, a traditional supply area Zone of Transco, prices in Zones 4, 5 and 6 will equilibrate; that is, they will converge.

Q. Why will prices converge across all three zones?

A. If Zone 4 becomes cheaper than Zone 5, the gas will sell in Zone 5, bringing down the Zone 5 price and bringing up the Zone 4 price; likewise if gas becomes cheaper in Zone 5 than Zone 6, it will sell in Zone 6 (bringing down the Zone 6 price) and the Zone 5 price will equilibrate upward to attract supply to meet demand. The effect of this shift will bring all 3 prices into relative parity. This is to the benefit of Zone 5, which can be supplied from both Zone 6 and Zone 4. In addition, the supply area portion of Zone 6, the Marcellus, will have 1.7 Bcfd more takeaway capacity as a result of Atlantic Sunrise which will have an additional price depressing effect on both of Zone 6's and 5's pools. In essence these pools, except on price spike days (which may still occur 1% of the time to the extent New York City demand served by Transco still has demand which can't be met by pipeline supply that has increased 17.6% as a result of the NESE project), will converge to prices close to those in the supply area.

Q. So in light of the effect of the Atlantic Sunrise project on prices in Zone 5, how would the Company obtain gas at prices even lower than the likely future Zone 5 prices with new pipeline capacity?

A. To the extent a generator wanted prices of gas to generate electricity that were even lower than future Zone 5 prices will be, it would have to look at two things. First, it would have to find a location where historically and currently, prices for supply were less than the sources that will bring down the Zone 5 prices as part of the Atlantic Sunrise project (i.e., the Marcellus). Second, it would have to look at the all-in cost of accessing those supplies; in order to achieve an overall reliable supply on a least-cost ***to ratepayers*** basis.

Q. How does the analysis that you've recommended relate to the IRP?

A. It is getting the ***overall least-cost to ratepayers***, that this proceeding, and the planning that should be conducted in this proceeding, should be concerned with. I understand that Virginia law requires that the Company's IRP identify the electric generation supply that will "provide reliable service at reasonable prices over the long term." In my opinion, in order to determine whether the proposed IRP meets this standard, the Company must perform comparative analysis of fuel logistics (oil and gas) considering all costs of its pipeline capacity portfolio, fixed and variable, versus alternatives, to arrive at all-in costs, which can be justified as "reasonable".

Q. Have you done an analysis of whether the Company could obtain gas at prices lower than the future price of Zone 5?

A. Yes. The Company has suggested that Dominion South Point (DOM SP), the pool at which shippers with Dominion Transmission (DTI) capacity can access supply, is advantageous—i.e. gas prices are lower, relative to other supply sources. Notably, while the Company now has a 15-year agreement that can access the Marcellus, as part of the Atlantic Sunrise project, discussed above, the Company did not seek capacity on Atlantic Sunrise during either of the Open Seasons held by Transco for Atlantic Sunrise. For the reason that these two supply areas, Leidy on Transco and Dominion South Point on DTI are also published supply price locations, I performed analysis comparing those two locations' historical pricing relationships. In this case a pricing relationship measures the basis differential between the two locations to ascertain which is priced more favorably than the other. That chart is below.

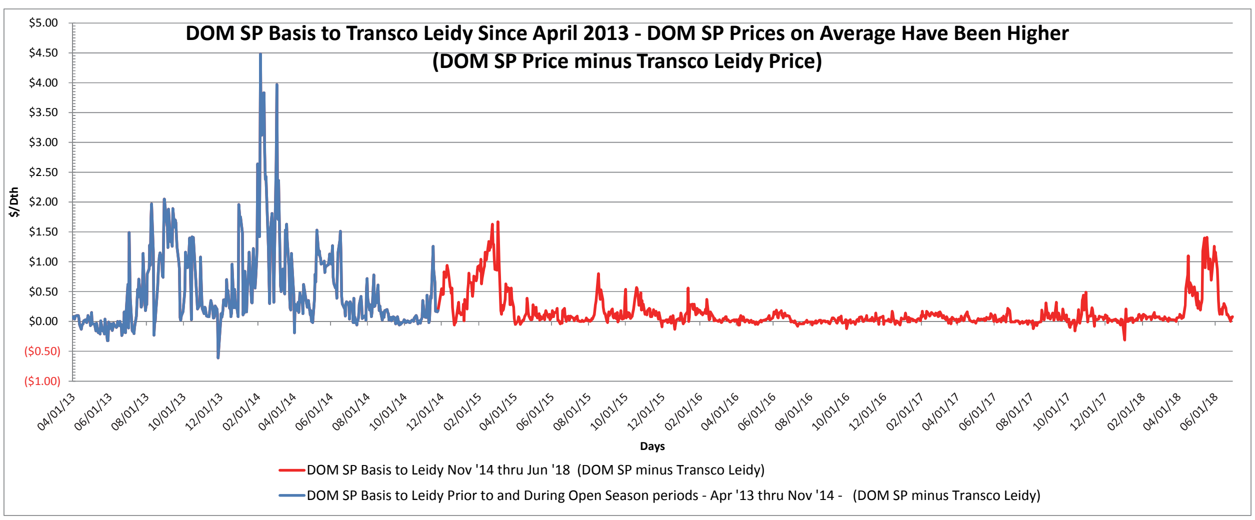


Chart 2

Q. What is this chart telling us?

A. This chart is constructed by looking at the difference in price between the two locations. The values you see are the price at Dominion South Point minus the price at Transco Leidy (the Marcellus supply area). A positive value (i.e., when the line is above zero) in the chart means that Dominion South Point was priced above that of Transco Leidy and conversely a negative value (i.e., when the line goes below zero, Dominion South Point is priced below Transco Leidy. As you can see, Dominion South Point is and almost always has been priced higher than Leidy.

Q. I see that, but the prices at these hubs are very close, at least currently, so doesn't that mean that there is equivalence between Dominion South Point and Leidy as supply points for the Company?

A. No. The answer to that question depends on how much it would cost to add access to that supply.

Q. Please explain.

A. Unless and until the Company could get access to more of the Dominion South Point gas, it can't incrementally benefit from lower gas prices at that hub, assuming a lower price exists. In order to gain such access, a new line, or an expansion of an existing line to Dominion South Point connecting the Company's plants to that Dominion South Point supply point would be the only way to gain increased access. That new line, or expansion of an existing line, costs money. Pipelines are only built or expanded if the pipeline developer signs contracts for 15-20 years guaranteeing them recovery of costs to build such facilities. That recovery of costs comes by means of payment by the shipper subscribing to capacity on that line of fixed reservation charges for the 15-20 year period.

Q. What are those costs?

A. Well, for the proposed Atlantic Coast Pipeline, which as planned would connect Dominion South Point to Zone 5, the FERC-approved maximum rate is currently $1.75 per Dthd of reserved capacity. I have estimated that anchor shippers, those whose subscriptions would enable the pipeline to be financed, might be as low as $1.40 per Dthd. However, in response to ER 8-11 (b), the Company stated that it is assuming such cost to be $1.70 per Dthd.

Q. Does that mean that the price of gas at Dominion South Point would have to be $1.40 to $1.75 cheaper than the price of gas at Transco Leidy to build the pipeline with no significant effect on the fuel costs passed through to Company ratepayers?

A. No, the above chart showed that Transco Leidy was preferable to Dominion South Point (i.e. gas prices were generally lower at Leidy) as a supply source based upon historic price relationships. To show the indifference point for Company ratepayers, whose electricity would otherwise be generated by Zone 5 priced gas, one would compare Dominion South Point to Transco Zone 5 prices historically, as well as assess what future prices at both Dominion South Point and Zone 5 are predicted to be based upon active futures trading involving the two locations or locations that would be the determiners of Zone 5 prices.

Q. Did you do that analysis?

A. Yes. However, first I need to provide a little background on the concept of "basis": how it is developed, how it is used in the gas market, and then, how basis figures into pipeline expansions and new pipeline construction. Simply put, basis is the difference in price of gas at two locations. Price is set at a location when a seller sells and a buyer buys, and that transaction is either recorded (like on an exchange) or is reported to price reporting journals. In North America, and increasingly across the world, the price of gas at the Henry Hub, where the largest exchanges trade futures, is the benchmark for gas prices. Then prices at other locations can be compared to the benchmark and a "basis" between the Henry Hub and that location is formed. In addition, basis can be calculated between two locations connected to each other on a given pipeline. In this situation, the basis is a proxy for the value of holding capacity on that pipeline to transport between these two locations. Finally, the difference between the prices at two locations not connected (or not sufficiently connected) by a pipeline can indicate the potential value of building an expansion, or new pipeline, to create (or increase) a capacity "path" that would connect these two locations.

Q. How did you use this basis concept to compare the costs of Dominion South Point and Zone 5 and identify the indifference point for Company ratepayers?

A. So, to analyze the potential value, and identify an indifference point for Company ratepayers, I looked at historic relationships between Dominion South Point prices and Transco Zone 5 prices. Note that for all charts depicting Zone 5 basis from Dominion South Point, the price reporting journal used was Natural Gas Intelligence (NGI), which began reporting Zone 5 prices on the August 31, 2004 trading day (for gas to be delivered September 1, 2004); and also note that on July 1, 2016, NGI broke out Zone 5 Prices into Zone 5 North (i.e., VA), Zone 5 South (i.e., NC and SC) as well as continuing to report an overall Zone 5 price. From and after NGI began reporting Zone 5 North as a separate pricing location, all my charts use the Zone 5 North prices, as they more accurately represent the Company's cost of gas purchased in Zone 5 for generation of electricity. A chart and analysis of what the Zone 5 basis has been is below.

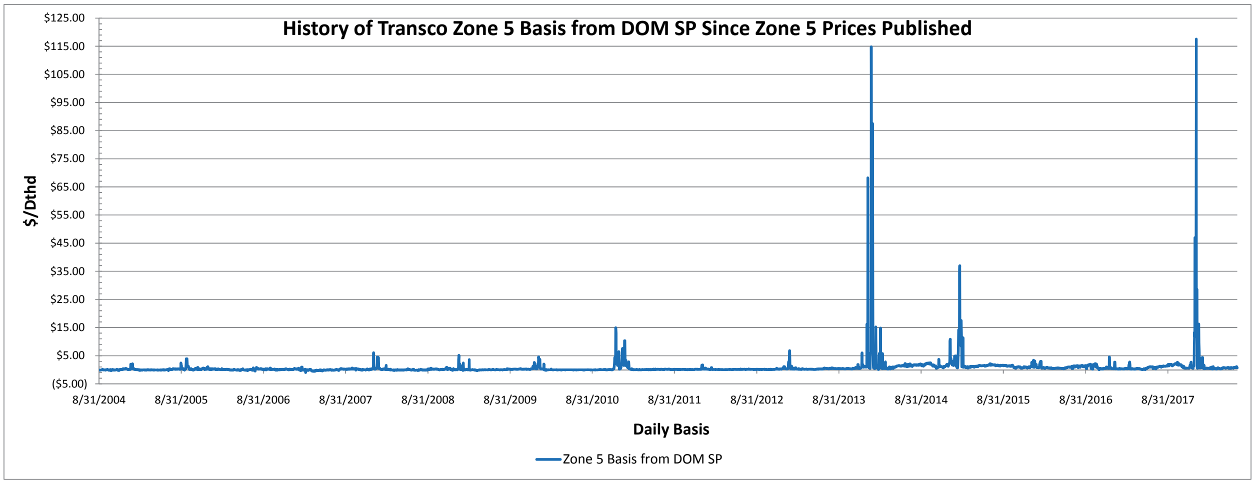


Chart 3

Q. What does this chart tell you?

A. As can be readily seen, with the exception of basis blow-outs (which show up as spikes on the chart), on this scale the basis of Zone 5 from Dominion South Point appears very low and largely consistent. In other words, the Dominion South Point and the Zone 5 prices are relatively close to one another over time. To get a closer view and see other relationships, the next chart changes the scale in order to get a more granular view of the basis relationships, (i.e., daily, average seasonal and average annual comparisons) between Transco Zone 5 and Dominion South Point since Transco Zone 5 prices have been published.

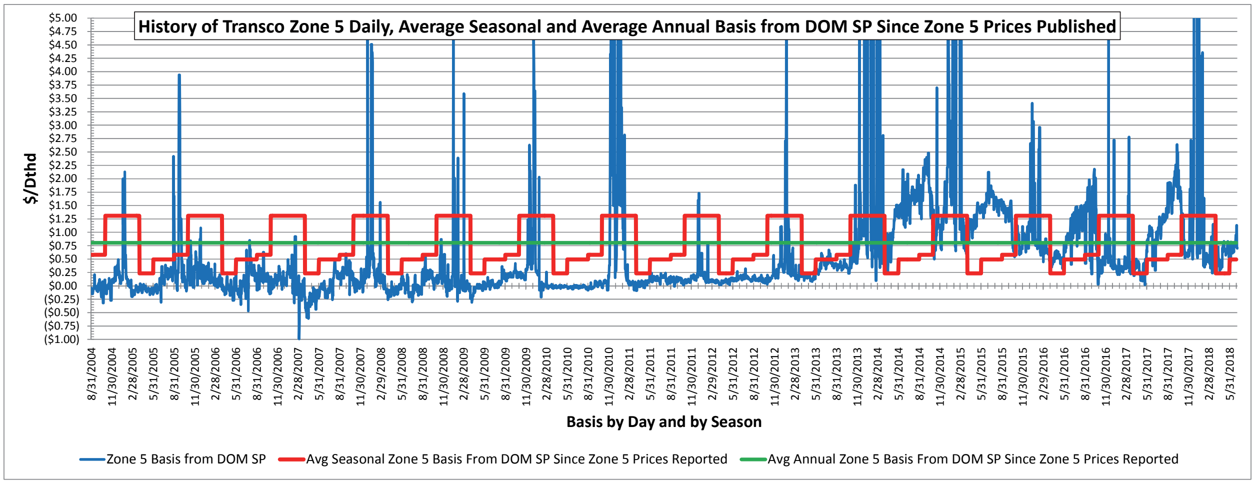


Chart 4

Q. What does this second chart tell you?

A. As can be seen in the above chart, which clips out basis blow-outs above $5.00, for the most part, the basis of Transco Zone 5 from Dominion South Point has had a particular seasonal pattern until recently. In the above, the seasons are the generally acknowledged seasons of the natural gas business. In the above, winter is November through March, the spring shoulder is April and May, the summer is June through August, and the fall shoulder is September and October. These average seasonal basis relationships are presented in red. The average annual basis across this period is the green line and the value is $0.81 over the 13 years and 10 months used in this chart. In other words, Dominion South Point gas prices have been, on average, $0.81 lower than Transco Zone 5 prices. Note also that the winter average basis has been approximately $1.30.

Q. Has this relationship changed over the last 5 years?

A. Yes. Now, taking a look at just the past five years, one sees a different relationship developing. Below in Chart 5, which is at the same scale as Chart 4, one sees the 3 periods of basis blow-outs (i.e., those periods where basis differential exceeds $35.00 per

Dthd). Note that these basis blow-out periods are directly related to the price spikes stemming from capacity constraints into New York City on the very coldest days.

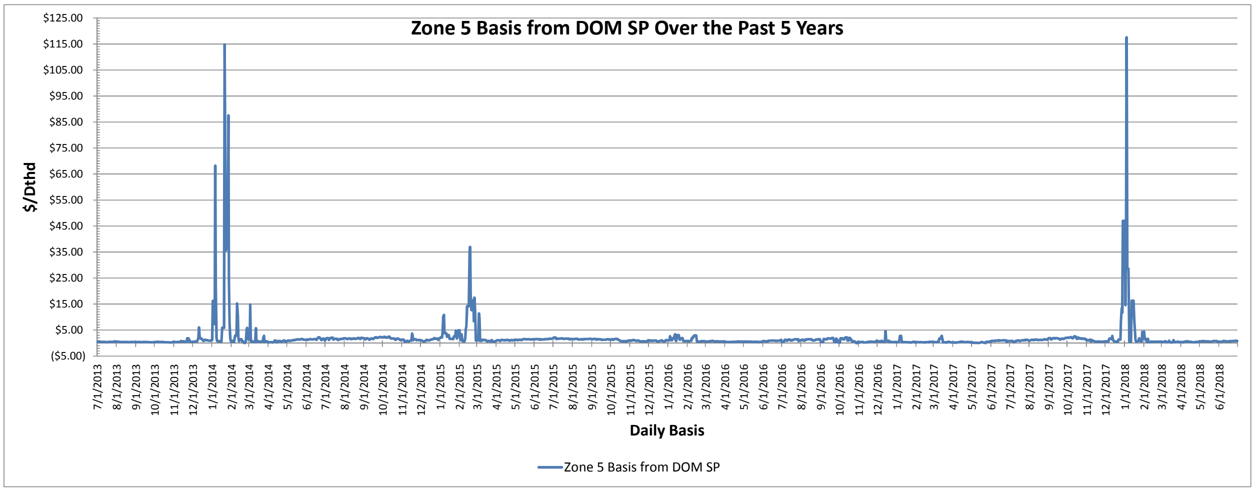


Chart 5

And, again to see a greater granularity, and observe the seasonal and annual relationship over the past 5 years, I present the below Chart 6, which is at the same scale as Chart 4.

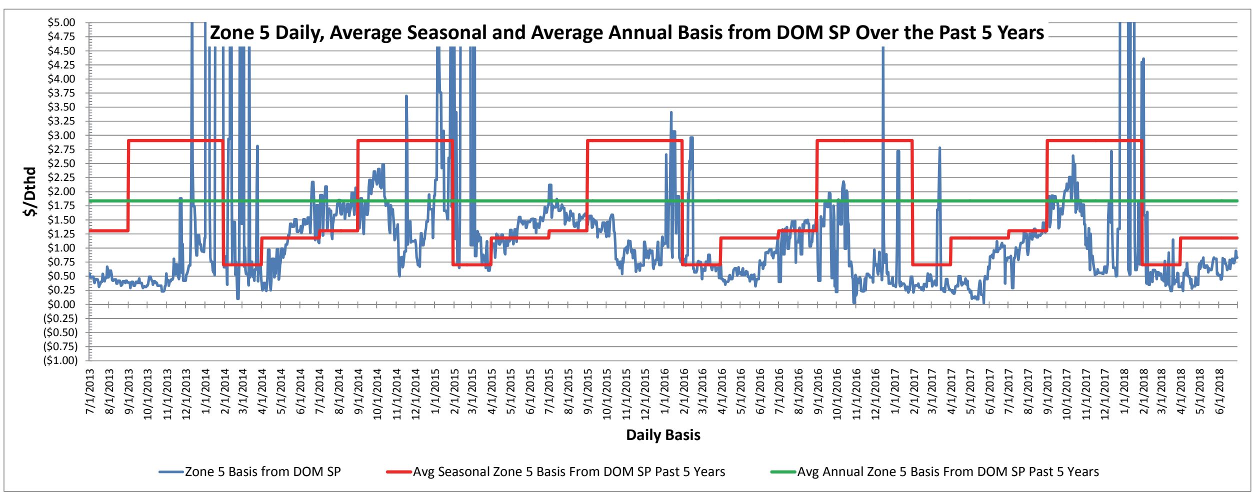


Chart 6

Q. This Chart 6 appears to show that the Annual Average Basis of Zone 5 from Dominion South Point exceeds $1.75 over the past 5 years. Is that the case and, if so,

wouldn't that indicate that creating a new path connecting Dominion South Point to Transco Zone 5 might make sense?

A. Not necessarily. In my opinion, this is where least-cost planning and further analysis is warranted. First, as the Company is generating electricity with a fuel, it has to consider alternate fuels (for example, fuel oil) as a means of avoiding the price spikes in the natural gas market. Second, from a least-cost planning perspective, the Company should also look to the future before undertaking and saddling ratepayers with the 15-20 year cost of a proposed new "path connecting Dominion South Point to Transco Zone 5." A prudent steward of ratepayer interests has to consider what other changes to capacity on Transco serving Zone 5, and influencing Transco Zone 6 Non-NY, are coming into play over the same time horizon to evaluate the prudency of a potential new path, like the Atlantic Coast Pipeline, between Dominion South Point and Transco Zone 5.

Q. Did you do this analysis?

A. Yes. I examined what the Zone 5 basis, from a Company ratepayer perspective, might be if the Company avoided the past 5 years' price spikes in natural gas by instead using fuel oil (and not buying gas) on the 12 occasions over the past 5 years that Zone 5 prices exceeded $35.00 (as discussed above $35.00 /Dth gas is the cross-over point where $4.00 per gallon fuel oil is less costly to generate electricity from than natural gas). A chart of the same type as Chart 6 with this means of addressing price spikes and the remaining prices is presented below.

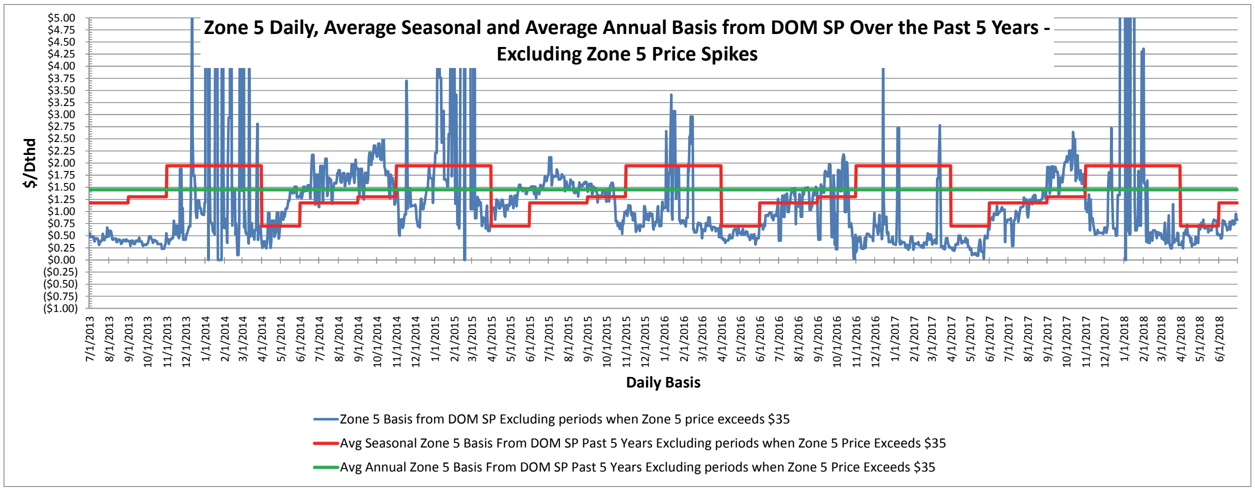


Chart 7

Q. What does this Chart 7 show you?

A. As can be determined from Chart 7, eliminating those 12 days when Zone 5 prices exceeded $35.00/Dth, drops the average annual basis along a path connecting Dominion South Point to Zone 5 to $1.45 per Dthd. Thus, prudent fuel source management eliminates nearly $0.40 per Dthd of value on average over the whole entire 5 years.

Q. But $1.45 is still greater than the low-end estimate of $1.40 that you estimated would be the negotiated rate that the Company might pay for a proposed new path connecting Dominion South Point to Transco Zone 5. Doesn't that mean that the new path would be a reasonable expenditure from the perspective of the Company's ratepayers?

A. No. In my opinion, before a least-cost planning utility like the Company embarks on pursuing a 15-20 year fixed cost commitment of ratepayer dollars for a new path, the level of diligence a prudent economic actor would undertake would be to look ahead, not just behind, and evaluate known recent and coming developments. Here I am referring specifically to what the natural gas market is saying about future prices and resultant future basis along the potential Dominion South Point to Zone 5 path.

Q. How does the natural gas market predict the basis will change along the Dominion South Point to Zone 5 path in the future?

A. Today, the organized over-the-counter futures markets and organized futures exchange markets trade and develop prices and basis at more than 70 pricing locations in North America. Among those are Dominion South Point and Transco Zone 6 Non-NY. Transco Zone 5 is listed as a trading location, but there are no trades currently listed for Transco Zone 5, nor have there been in the last 10 years. Anecdotally, this is in part due to the liquidity and close seasonal correlation historically between Zone 6 Non-NY pricing and Zone 5 pricing in the daily and monthly markets. A chart depicting the daily basis as well as average seasonal basis values relationship over the 13 years and 10 months of since Zone 5 prices have been published is set forth below.

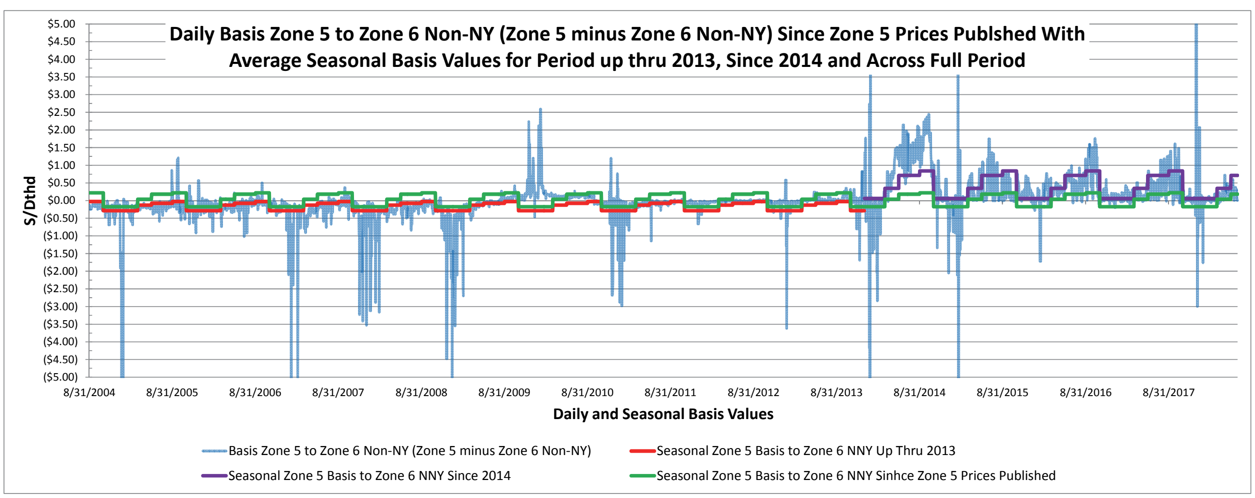


Chart 8

Q. What is the purpose of the comparison in Chart 8?

A. The purpose of deriving seasonal basis values is to apply those seasonal basis values to forward Zone 6 Non-NY prices to impute a forward Zone 5 price. This, in turn, allows a derivation of a forward value of the potential Dominion South Point to Transco Zone 5 Path. In Chart 8, one can see the daily basis with the scale truncated at plus and minus $5.00 (note, however, that the values were not truncated for average seasonal value calculation purposes). In the above, a positive value means that Zone 5 is more expensive than Zone 6 Non-NY; while a negative value presents that Zone 5 gas is less expensive than Zone 6 Non-NY. Historically, Zone 5 prices tended to be less expensive than Zone 6 Non-NY prices. That historic relationship demonstrably changed around the beginning of 2014. The red line above is the average seasonal basis of Zone 5 to Zone 6 Non-NY up through 2013. The purple line depicts the average seasonal basis since 2014. The green line depicts the average seasonal basis of Zone 5 to Zone 6 Non-NY since Zone 5 prices have been published.

Q. What was the next step of your analysis after deriving these seasonal basis values?

A. After deriving these seasonal basis values, I generated 4 cases projecting the Forward Value of a potential Dominion South Point to Transco Zone 5 Path. Below I describe each case and present the associated chart.

Q. Please explain Case 1.

A. Case 1 shows the forward value of the potential path as it looked in November 2014, a time when the Company was involved in pursuing the Atlantic Coast Pipeline; and, as a diligent least-cost planning utility would (or at least should) have assessed what the value to ratepayers of such an undertaking looked like at that time (i.e., a risk/reward assessment on behalf of ratepayers). In Case 1, I used the prior 2 years (to November

2014) average seasonal Zone 5 to Zone 6 Non-NY basis to apply to the forward period. The two years prior to November 2014 were those over which both the Dominion South Point basis was blowing-out to the negative and the Zone 5 Basis to Zone 6 Non-NY was also increasing to the positive. Below is Chart 9.

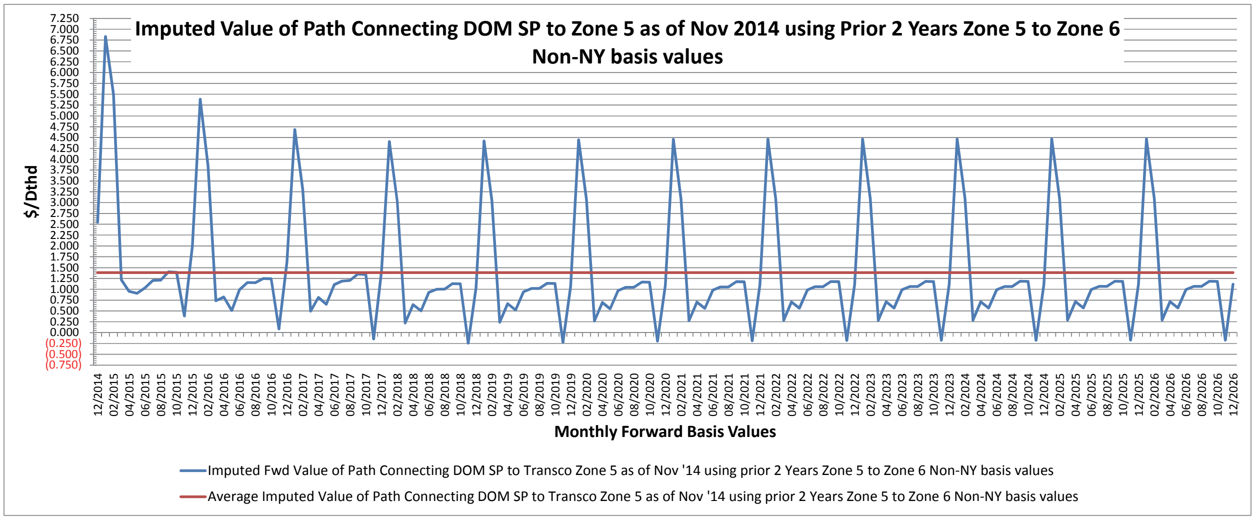


Chart 9

Q. What does this chart tell you?

A. As can be seen in Chart 9, using the preceding two years' basis relationship between Dominion South Point and Transco Zone 5, the presented Forward Value of a potential Path connecting Dominion South Point to Transco Zone 5 varied by season and would have had an average annual value of \$1.386/Dthd. In other words, the trend of prices in November 2014 (based on the immediate prior two years' experience) predict that Dominion South Point prices would be \$1.386/Dthd lower than Zone 5 prices, a difference that is a fraction lower than the lowest likely transportation cost of the Company's capacity reservation on the Atlantic Coast Pipeline. In this scenario, Dominion South Point gas prices plus fixed costs at 100% load factor and Zone 5 all-in variable costs are approximately equivalent from the perspective of Company ratepayers[4]. However, Case 1 ignores the very likely impact of contemporaneously known future developments impacting Zone 6 Non-NY as well as Zone 5. That is why a prudent and diligent least-cost planning utility wouldn't stop at only assessing the risk/reward for ratepayers associated with Case 1.

Q. What does Case 2 show?

A. Like Case 1, Case 2 also shows the forward value of the potential path as it looked in November 2014 (i.e., when the Company was involved in pursuing the Atlantic Coast Pipeline). However, unlike Case 1, Case 2 accounts for the effects of other pipeline projects with binding precedent agreements for capacity targeting Zone 5 by using the historic basis relationship between Dominion South Point and Transco Zone 5 (i.e., a history that covers when the two pricing areas did not demonstrate a depressed Dominion South Point supply area price which has recently developed and would be relieved by a new pipeline). In my opinion, a diligent least-cost planning utility would (or at least should) have assessed what the value to ratepayers of an undertaking like the Atlantic Coast Pipeline would look like after taking into account other projects with binding precedent agreements for capacity targeting the same Zone 5 (as well as the Zone 6 Non-NY extent of Transco) as is the Atlantic Coast Pipeline (for example, Atlantic Sunrise with 1.7 Bcfd and Mountain Valley with another at least 1.7 Bcfd). To take account of such developments, the Company should have also assessed what the potential Forward Value of a new Dominion South Point to Zone 5 Path might be if the forward Zone 5 basis to Zone 6 Non-NY returned to the same relationship as the Average Seasonal and

[4] Note this is only true with the assumption that the Atlantic Coast Pipeline, which makes the Dominion South Point to Transco path, was to be utilized at 100% capacity 365 days per year for the full period of the Contract.

Average Annual basis that had been true since Zone 5 Prices were reported up through October of 2014. After all, adding 3.4 Bcfd to Transco (let alone nearly 5 Bcfd if the Atlantic Coast Pipeline were included) would certainly change things from what they had been when looking at basis relationships only during the most recent basis blow-out period.

Q. Did you do this analysis?

A. Yes. The Chart taking into account such market reactions and return to more historic basis relationships is set forth in Chart 10 below.

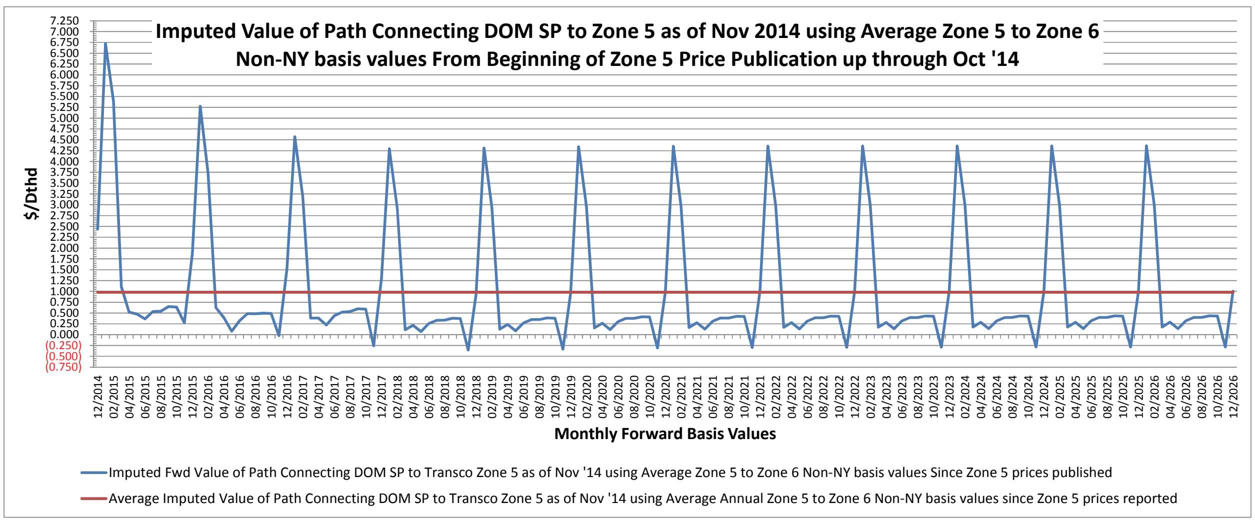


Chart 10

Q. What does Chart 10 tell you?

A. As can be seen in Chart 10, the annual average basis—that is value of a potential path connecting Dominion South Point to Transco Zone 5—changes dramatically. This November 2014 analysis (which includes price spike and basis blow-out periods) shows that the potential value of the potential path drops in value to ratepayers from \$1.386/Dthd to \$0.978/Dthd, a drop of more than \$0.40 per Dthd. Stated another way, this risk, which was knowable in November of 2014, was that ratepayers would potentially pay, on average, $0.40/Dthd more on 300,000 Dthd every day for 20 years – or $876,000,000 over that period. I will discuss below, in my conclusions, the apparent lack in this or last year's IRPs of any discussion of justification, or discussion of risk mitigation associated with the Company's obligation to undertake both least-cost planning as well as anticipate and plan for mitigating potential knowable likely risks to ratepayers.

Q. Please explain Case 3.

A. In Case 3, I depict what the current Forward Value of the potential Dominion South Point to Zone 5 Path looks like today based upon current (June 29, 2018) forward market values of Transco Zone 6 Non-NY basis, current (also June 29, 2018) forward market values for Dominion South Point and an assumed (although unlikely) forward basis relationship between Zone 5 and Zone 6 Non-NY staying as it has been since the beginning of 2014 (i.e., over the past 4 and a half years relative basis depression of Dominion South Point coupled with the relative basis elevation of Zone 5 relative to Zone 6 Non-NY). This Case 3 is set forth in Chart 11 below.

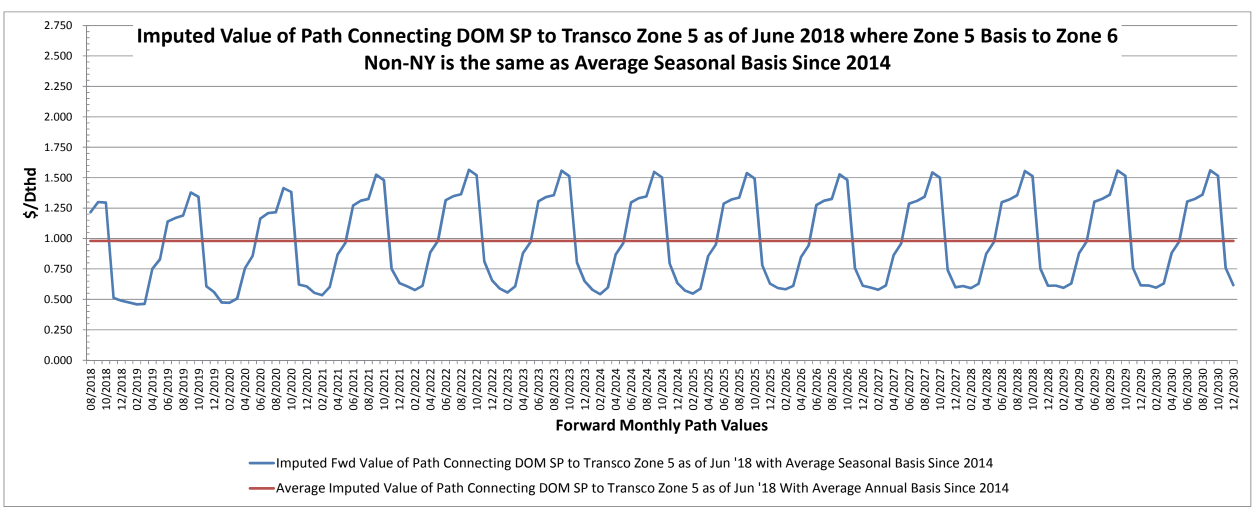


Chart 11

Q. What does Chart 11 tell you?

A. As can be seen in this Case 3, even with the assumption that average seasonal Zone 5 to Zone 6 Non-NY basis relationships remain the same in the future as they have been since 2014 (i.e. the same as they have been during the recent blow-out period), the annual average value of the potential path connecting Dominion South Point to Transco Zone 5 is less than $1.00/Dthd, well below the $1.40/Dthd to $1.75/Dthd necessary to offset the transportation costs of capacity reservations on the proposed Atlantic Coast Pipeline. While this Case 3 is instructive, in my opinion, a diligent least-cost planner should, from at least a risk assessment point of view, perform analysis similar to that I make available below in Case 4.

Q. Please explain Case 4.

A. Case 4 (Chart 12) depicts what the current Forward Value of the potential Dominion South Point to Zone 5 Path looks like today based upon current (June 29, 2018) forward market values of Transco Zone 6 Non-NY basis, current (also June 29, 2018) forward market values for Dominion South Point and what the current Forward Value of the potential Path is should the forward basis relationship between Zone 5 and Zone 6 Non-NY be the same as the average seasonal value since Zone 5 prices have been published.

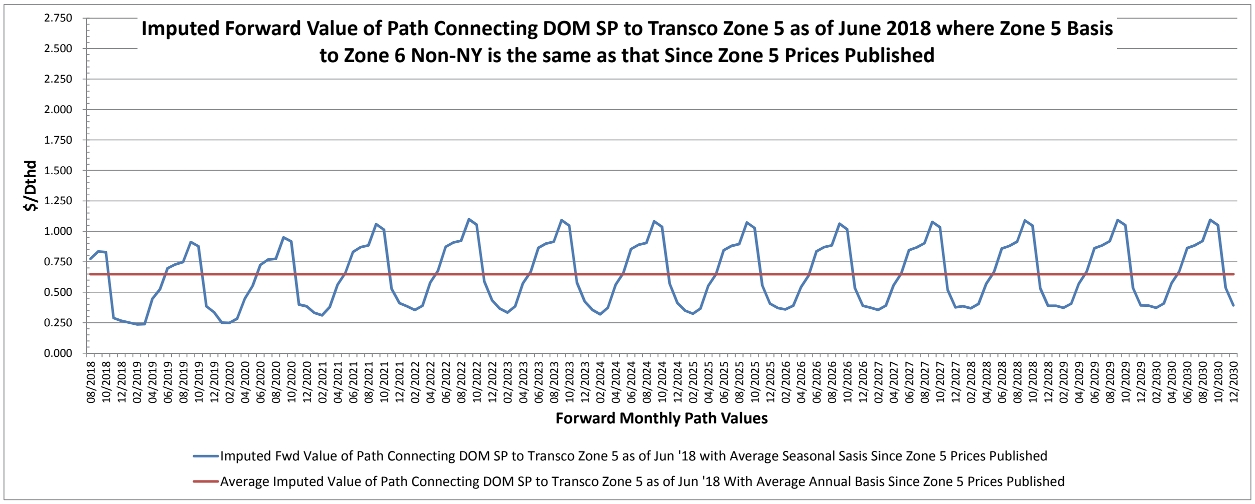


Chart 12

Q. What does Chart 12 tell you?

A. As can be seen in the above depiction of the Forward Value of the potential path connecting Dominion South Point to Transco Zone 5, when Average Seasonal and Average Annual basis relationships between Zone 5 and Zone 6 Non-NY (i.e., those that reflect the averages across the full period since Zone 5 prices began to be published—since Sept 2004—which notably include the 2014 to present period of depressed Dominion South Point basis and elevated Zone 5 basis relative to Zone 6 Non-NY) are used, the value to ratepayers plummets to less than $0.70 per Dthd. The implications of this analysis are that ratepayers are exposed to paying at least $0.70/Dthd ***more* than the value of the path** (assuming the most favorable $1.40 rate per Dthd for transportation on the proposed Atlantic Coast Pipeline applies) every day for 20 years. This amounts to a ratepayer exposure of over $1.53 billion in costs in excess of value. Moreover, should the potential Atlantic Coast Pipeline rate of $1.75 apply, or the $1.70 rate provided in the data response cited earlier apply, ***ratepayer excess cost*** over value rises to between $2.19

billion (in the $1.70 per Dthd case) and nearly $3 billion ($2.999 billion in the $1.75 per Dthd case) over 20 years.

Q. Of the four cases you have presented, which is the most likely to occur?

A. In my opinion, Case 4 presents the most likely depiction of the Forward Value of a potential Dominion South Point to Transco Zone 5 path.

Q. Did the Company provide any data from which you could make similar charts and assess the value and cost of a potential path from Dominion South Point to Transco Zone 5?

A. While the Company provided no analysis similar to what I have done above, it did provide data in two data responses from which I have made a similar forward-looking chart to those above. Those two responses were ER 8-11 (b) and ER 7-3 (c).

Q. Were you able to perform an analysis using these responses?

A. Yes. In ER 7-3 (c) the Company provided its forward prices for Dominion South Point and Transco Zone 5. From that response, I took the prices for the December 2019 through November 2039 period: the 20-year period of a potential contract for the potential path connecting Dominion South Point to Transco Zone 5. The prices I took were for Dominion South Point and Transco Zone 5, and I calculated a basis for that path by subtracting the Dominion South Point price from the Transco Zone 5 price to identify the basis—that is the value that such a path would have across the forward looking 20-year period. Then, from the Company's response to ER 8-11 (b), I took the cost that the Company is using for the creation of that path. That response indicated that the cost would be $1.70 per Dthd. Below is the chart generated from the Company's data.

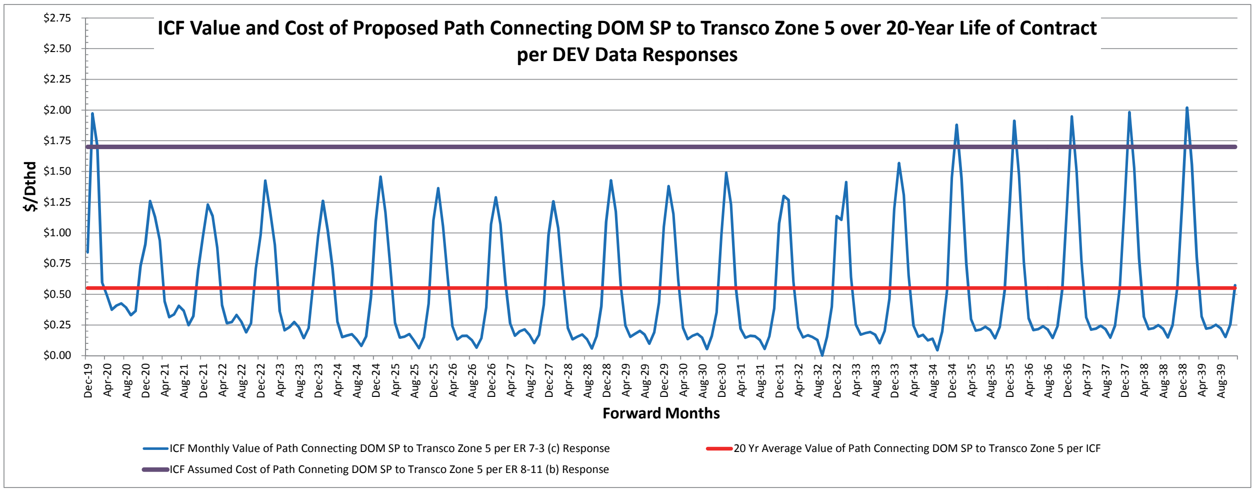


Chart 13

Q. What does Chart 13 tell you?

A. It tells me from the Company's own data that over the 20-year life of the contract, ratepayers will experience no net value from paying for the path connecting Dominion South Point to Transco Zone 5. In fact, the Company sets the average annual value at $0.55 per Dthd, while the cost to ratepayers, according to the Company, will be $1.70 per Dthd. Using the Company's data, the ***net cost***, as of its December 29, 2017 study date, is calculated to be $1.15 per Dthd. Applying this to a 300,000 Dthd subscription for 365 days per year for 20 years brings the 20-year ***excess of cost to value*** amount to $2.5 billion. On average, that is greater than $100 million per year.

Q. Moving on to the second area of your testimony, you stated that the Company should have, as part of its 2018 Plan, undertaken an evaluation of load duration curves for the purpose of identifying what resources and fuels would be the least-cost resources and fuels on an all-in cost basis to meet such load curves. Please elaborate on this point.

A. In my opinion, the Company should have examined its load duration curves and then matched resources – including fuel source – to match to the curves on a least-cost basis. Only in this way can the Company ensure that it is identifying the best matched resources, as well as the most reasonable means of fueling those resources based upon the expected load factor at which those resources will be utilized, taking into consideration minimization of fixed costs, where variable all-in fuel costs are more reasonable than (those all-in fuel costs are) when fixed and variable fuel costs are considered at projected load factors.

Q. Why does that matter?

A. Given the Company's increasing reliance on natural gas, as described in its 2018 Plan, and its apparent lack of explicit planning to provide for dual fuel capability at both its combined cycle and combustion turbine facilities, Company ratepayers are faced with potentially very high fixed costs to power units like the generic CTs identified in the Plan that will have very low load factors, i.e., these facilities will run very infrequently. This low-load factor reality makes the all-in cost per unit of natural gas actually used to generate electricity very high indeed.

Q. Did you generate indicative load duration curves in your analysis?

A. Yes. The first such curve that I generated based upon the Company's data was a recently experienced, maximum hourly load/demand curve.

Q. What is a Maximum Hourly Load curve?

A. Based upon data provided by the Company to Staff of hourly demand of DOM LSE for the years 2014, 2015, 2016, 2017 and 2018 year-to-date, I lined up every hourly Load/Demand table in calendar date and hour order. I eliminated the leap day in 2016.

Then I took the maximum demand expressed over that period in each hour of the period, and then with that max hourly demand I sorted from highest to lowest demand. Next, I plotted this Max Hourly Demand curve against existing round-the-clock generating resources. To gauge the steepness of this derived demand duration curve, I display only the highest 720 hours (i.e., equivalent of 30 days). Below is a chart depicting the results of the above exercise.

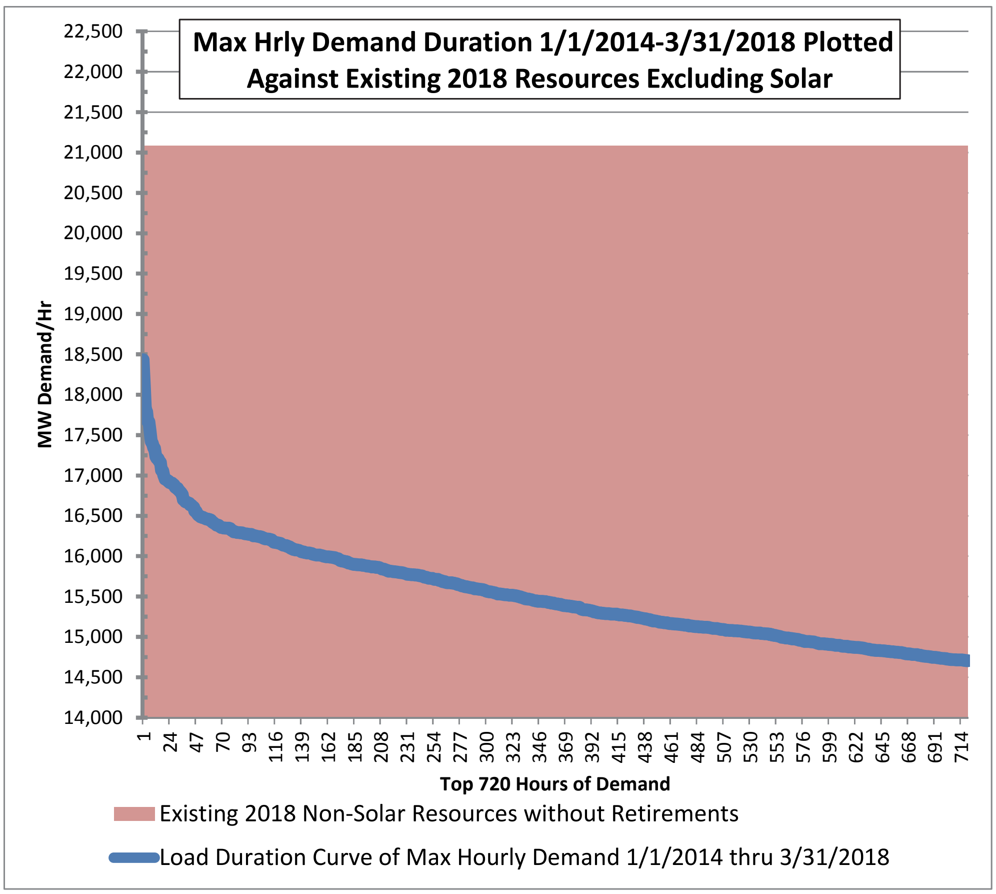


Chart 14

Q. Why did you do this?

A. What this sort of analysis allows you to determine is whether there has been a particular time of day and season of the year in which peak demand has occurred. Earlier in my testimony, I identified several basis blow-out periods beginning in 2014. Based on my understanding of the mechanics behind these blow-out periods, I thought it was likely that the Company would have experienced demand peaks during these same periods.

Q. What did you find?

A. I found that in recent years, the Company has experienced short-term demand spikes during winter early morning corresponding with extreme cold weather events like the Polar Vortex and the Bomb Cyclone. In addition, I found that 321 of the top 720 demand hours were winter hours. The range of demand in the top 720 hours, sorted in the manner described above, ran from a high of 18,434 MW on February 20, 2014 at 8:00 AM down to 14,704 MW on January 1, 2014 at 5:00 AM. This also means that for 8,040 hours, sorting the max demand expressed in any hour of the January 2014 thru March 31, 2018 period, the maximum demand was less than the 14,704 MW/hr., according to the data supplied by the Company.

Q. What is the significance of these findings?

A. A couple of things are significant. First, it is clear from this sort of demand duration analysis that the resources required to meet the top hours of expressed maximum demand have a very low load factor utilization. Second, given the hours of peak demand that have been expressed during extreme winter weather in 2014 and 2018, the addition of substantial solar will not address these "winter morning hours" demand coverage requirements.

Q. What is the problem the Company faces?

A. The problem that the Company faces, and one that it makes no mention of in the 2018 Plan, is that sometime in post 2022, with the planned retirement of its Yorktown 3 and Possum Point 5 (heavy oil peaking units), at between 5:00 AM and 9:00AM – with a heavy concentration around 8:00 AM on some winter day during an extreme weather event like the Polar Vortex or Bomb Cyclone, the Company will need to call on a resource to either add supply or subtract demand. The Company will need this resource for a few hours in any of the years between 2023 and at least 2028 (10 years from now) and will need it for at most an estimated 220 -225 hours per year out of 8,760 hours per year. In other words, the resources (both generation and associated fuel logistics resources) needed to meet a short, winter demand spike caused by an extreme weather event will be utilized at a very low load factor, i.e. they will operate very infrequently.

Q. How will the Company meet such an electric demand spike according to its 2018 IRP?

A. According to the IRP, the Company intends to rely on CTs to meet this demand.

Q. In your opinion, how should the Company address this problem?

A. In my opinion, the Company has multiple options that it should consider in the 2018 IRP. First, it should evaluate whether to keep online its 2 Peaker Heavy Oil units (total ~1,500 MW winter) because extreme weather demand spikes can most economically be met by those units. For instance, without retirements, the Company has 21,087 of Day-Round (i.e., non-solar) generating capacity versus 18,434 MW of load which was its highest winter hourly demand in 2014 (note 18,434 MW was also highest DOM LSE hourly demand). Thus, by keeping the 21,087 MW of existing generation, this level is projected to satisfy (absent anything else like demand response leading to demand reduction) projected requirements for an extreme winter weather event until winter of 2025/2026. Keeping the heavy oil-fired units available is also keeping the generation (plus fuel) that is the most economical on an all-in cost basis, because it does not require any additional pipeline capacity beyond that held today, to fuel generation to meet the demand.

Q. What about the Company's proposed CTs?

A. A second option for the Company would be to make all of its proposed CTs dual fueled so that they can run on diesel. The benefit of dual fueled CTs is that given the prevalence of electricity import capability from the rest of PJM, the option value of the dual fueled resource derives from the fact that not only may the dual fired CTs not be called on (when import capability exists), but the Company can also sell that dual-fueled resource in PJM's capacity performance market without having to commit to expensive long-term pipeline capacity. In other words, the reason for the Company to have dual fuel capability at its CTs is to avoid burdening Company ratepayers with the cost of additional pipeline capacity that has to be paid for 365 days a year but used only infrequently.

Q. Isn't installing dual fuel capability expensive?

A. Not on a comparative, all-in cost basis.

Q. What does all-in cost mean in this context?

A. By all-in cost, I mean the all-in cost per increment of solution to close the gap of unmet demand caused by an extreme winter weather event that could exist in the future. Let's use a hypothetical scenario. Assume for a moment that new pipeline capacity costs $1.40 per Dthd. That means to reserve such capacity it costs $511.00 per year to reserve 1 Dthd. Further, assume that this capacity is fully used 360 hours in a year, or the equivalent of 15 days per year. The all-in cost of the capacity when used is more than $36.00 per Dth used ($511.00 divided by 15 days). Add to that a winter time gas cost in

2029 of $3.97, and the total becomes nearly $40.00 per Dth actually used to make electricity.

Q. How does that cost, i.e., the cost of new pipeline capacity and gas, compare with the cost of fuel oil projected by the Company in the Plan?

A. The Company projects that fuel oil cost will be $18.00 per Dth (MMBtu) in 2026. Therefore, the cost of fueling the CTs in the winter using firm pipeline capacity plus the gas is projected to be fully twice the cost of using fuel oil ($40.00 per Dth vs. $18.00 per Dth). This is the reason I recommend that the Company evaluate fueling the CT units, and even any CC unit (beyond the one able to be accommodated with existing capacity) with fuel oil during the peak demand portions of future winter periods. As set forth in the table below, I calculated the relative cost (based upon Company estimates) of building oil-backup fueling facilities (including sufficient storage to hold four run days of fuel) sufficient to power a Combustion Turbine with a winter rating of 188 MW with oil during peak demand periods versus subscribing to capacity on the Atlantic Coast Pipeline to provide the same energy during peak periods. In this comparison, I also use Company estimates for cost of oil and cost of gas to arrive at an all-in cost comparison.

Modeling Comparative Cost of Dual Fuel Back up versus New Firm Pipeline Capacity

$/Kw Installation of Dual Fuel Storage 1/	kw/MW	Winter MW of Generating Unit 2/	Cost of Installing Dual Fuel Back-up	Heat Rate (Dth NG /MW) 3/	Dth/Hr	Dthd of Pipeline Capacity to Achieve Hourly Fuel Delivery	Cost/Dthd Subscription to New PL Capacity 4/	Days	Annual Cost of Firm Pipeline Capacity
$24.00	1,000	188	$4,512,000	11.2	2,106	50,534	$1.40	365	$25,823,078

Hours Run per Year	Equiv. Days Run per Year	Oil Cost per Dth 5/	Dth Oil Used	Cost Oil Used	Dth Gas Used	Gas Cost per Dth 6/	Cost Gas Used		Fuel Cost Differential (Oil Cost minus Gas Cost)	Years	Savings of Dual Fuel over Life of New PL Capacity Contract
218.0	9.1	$18.00	553,284	$9,959,112	459,021	$3.97	$1,821,548		$8,137,564		
								Annual Savings/Yr over PL Cost	$17,685,514	20	$353,710,279
								Simple Payback of Installation of Dual Fuel Capability in Yrs	0.26		

11.2	Gas Heat Rt
13.5	Oil Heat rate
1.21	Heat Rate Ratio of Oil Dth to Gas Dth
	https://www.eia.gov/electricity/annual/html/epa_08_02.html

1/ From Company Response to Staff Set 9-107 (f)
2/ Winter rating of a CT equivalent to Remington 3 Unit per Company Data
3/ Personal knowledge of latest generation Combined Cycle Plants
4/ Based upon estimated Foundation Shipper Rate on ACP as a proxy @ 80% of $1.75 ACP Recourse Rate
5/ No.2 Fuel Oil Cost Estimate per Company Projections 2026
6/ Winter Month (Dec-Feb Avg) based upon Company Projections of DOM SP in 2029 Shaped per CME 2026 Futures

Table 1

Q. What does Table 1 show?

A. As can be seen from this comparison, the annual cost of pipeline capacity subscription to supply a 188 MW CT is $25.8 million. While the annual cost of firing with oil for an estimated 218 winter hours that such unit may be called upon to run is $8.2 million higher than the 218 hours of natural gas, there is an annual savings (even with a higher fuel oil cost) of $17.7 million. This means that the cost of installation is paid back in simple payback terms in less than a third of a year. This relative cost savings over a 20 year term of pipeline capacity subscription would mean that ***for every 188 MW CT the Company proposes to install ratepayers are at least $350 million better off with the dual fuel option.*** In addition, with respect to run time, I should note that not all CTs would run as many hours based upon the demand duration curve, thus leading to an even wider cost differential and ratepayer savings. I picked 2026 as the reference point for this comparison as it represents approximately the mid-point in time between 2019 and 2034.

Q. Are there any other attributes to dual fuel capability that the Company should consider in its 2018 IRP?

A. Yes. With the optionality that installed dual fuel capability gives, the Company could opportunistically avail itself of vaporized LNG from either of Cove Point, Elba Island or Piedmont (including Piedmont's planned addition of a 1 Bcfd vaporization facility). This opportunistic purchase and scheduling of LNG from either of these locations is possible because depending on the flow direction of Transco on any given winter day, such receipts would be delivered by displacement. In the gas business, displacement means the following: if net physical flow on Transco is north to south and a power plant is between the north and south points (i.e., is in Zone 5 between the northerly Zone 6 and the southerly Zone 4) then injecting gas at the bottom of Zone 5 (where Elba Island is located) means that the Elba Island gas goes to the south to Zone 4 while gas that would otherwise have to traverse Zone 6 and Zone 5 would be delivered to the Zone 5 plant(s). Likewise, should the net flow be from Zone 4 to the north, injecting gas at Cove Point into the Cove Point LNG pipeline and delivering that gas to Transco at the top of Zone 5 means that gas traversing Zone 5 on the way north to Zone 6, would be delivered to the plant(s) in Zone 5 while the Cove Point gas would go to the north. In either event, it means that no new firm pipeline capacity would be needed to obtain such supplies.

Q. Are there any other options that the Company should evaluate in its 2018 IRP?

A. Yes. I alluded to two options above that warrant some additional explanation. First, it is very likely that the Company could purchase energy from PJM to meet demand spikes caused by extreme winter weather. Nothing in the IRP suggests that PJM, a summer peaking regional transmission organization, would not have excess energy available during the winter months. In addition, demand response programs could sufficiently dampen the demand effect of an extreme weather event such that additional resources are not necessary. Finally, battery storage is another option that warrants consideration. The Company has not evaluated any of these options in the 2018 IRP.

Q. Overall what is your recommendation about how the Company can meet the demand spikes identified by your load duration analysis?

A. My overall recommendation is, in short, that the Company should meet demand spikes driven by extreme winter weather in the most reasonable, least-cost manner, which requires that the Company balance resources, their fuel requirements and the Company's load duration curves. In my opinion, in light of the presence of low load / utilization factors, the Company should minimize fixed costs associated with both the generating asset itself and the associated fuel and fuel logistics. The steeper the decline in demand from peak hours to less peak hours, the more a right-sized means of addressing those spikes is essential and new pipeline capacity will be a costly, burdensome option for ratepayers. And from what I have read in the 2018 Plan, the Company has done none of the balancing that I recommend.

Q. Going back to your observation of the extreme weather-related demand spikes in 2014 and 2018, what else does your analysis show?

A. It shows that when a 5:00 AM to 8:00 AM winter hours' demand spike hits (and the heavy oil plants are retired), not even the Atlantic Coast Pipeline will be able to address the need to fuel generation to meet the demand, because the Atlantic Coast Pipeline does not serve the plants that need the gas, i.e. it does not have a connection to the CT plant or plants that will be used to meet this peak winter early morning demand. It's that simple.

Q. Please explain what you mean and why that is important?

A. It is important because if the Company wants to fuel power plants at that precise time of the day, i.e. the 5:00 AM to 8:00 AM period on winter mornings during an extreme weather event, it has to have fuel. If the CT plant intended to meet this demand gap is only gas fired, the Company has to have firm pipeline capacity to run that CT plant, and if the Company has to have firm winter capacity, utility ratepayers will be asked to pay for it 365 days a year[5]. If the plant can be fired by natural gas or light fuel oil, like diesel generally, then the Company does not have to have firm natural gas pipeline capacity and it saves that fixed cost expense and, importantly, utility ratepayers do not have to pay that fixed cost expense.

Q. What are the conclusions of your testimony?

A. First, the Company did not study or present any analysis of the cause, frequency, duration or magnitude of natural gas price spikes and did not assess what infrastructure developments are already underway and under development that could reduce, if not eliminate, the frequency, duration, and magnitude of such price spikes. In my opinion, such an analysis is necessary for the Company to identify a reasonable least-cost planning scenario in its 2018 IRP.

Second, analyzing four scenarios for forward looking basis projections, two related to what those projections would have looked like in 2014 and two related to what

[5] In the natural gas pipeline business it is widely recognized that aside from Florida and southernmost California pipelines' system demands peak in the November through March (i.e., winter) period. As a result, in order to reserve winter pipeline capacity, especially on fully subscribed pipelines, shippers have to agree to reserve and pay for 365 day per year service.

projections look like today, for the basis between different pricing locations, I calculated the ***net cost*** to Company ratepayers, (a net cost that is avoidable), of new pipeline capacity connecting Dominion South Point to Transco Zone 5 where the Company's generation facilities are located, i.e. the same path as the proposed Atlantic Coast Pipeline, to be as high as $3 billion over the next 20 years. I corroborated my analysis using natural gas price data provided by the Company which showed a net cost to Company ratepayers of the Atlantic Coast Pipeline to be $2.5 billion over the next twenty years. Based on these analyses, Company ratepayers will experience no net value from paying for the path connecting Dominion South Point to Transco Zone 5 as the Atlantic Coast Pipeline would.

Third, the Company presented no evidence that it examined either generation or associated fuel logistics load factors in its assessment of what is the least-cost generation scenario in its 2018 IRP. In my opinion, an examination of generation and associated fuel logistics load factors should be a required element of the Company's 2018 IRP.

Fourth, the Company did not present a cost justification for retirement of at least two of its units proposed to be retired totaling 1,597 MW (winter rating) of peaking capacity. The Company also fails to explicitly articulate, as part of its 2018 Plan, a plan for having dual fuel capability at all under-construction and planned future Natural Gas CC and CT units. Each of these options could eliminate the need to add any costly firm, pipeline capacity. In my opinion, a consideration of cost justification for retirement and consideration of the costs of dual fuel capability should be required elements of the 2018 IRP.

Fifth, the Company failed to assess the availability of vaporized LNG as a reasonable source of supply which could be delivered through existing lines on peak demand hours and days; thereby avoiding the fixed costs of additional pipeline capacity. In my opinion, the consideration of vaporized LNG delivered through existing lines on peak demand hours and days should be a required element of the 2018 IRP.

Sixth, had the Company analyzed its load serving requirements and projected load serving requirements with demand duration curves as part of their least-cost planning, it would see that the load factor of its projected demands is so low that meeting such demands with gas-fired only units is not prudent from a fixed-cost incurrence perspective. Multiple other alternatives are available to the Company, including not retiring certain heavy oil units, installing dual fueled CTs, power purchases from PJM, demand response, and battery storage that would provide a cost advantage over investment in new pipeline capacity to serve new gas-fired generation. In my opinion, consideration of these other alternatives to meet demand during peak hours and days should be a required element of the 2018 IRP.

Seventh, given the apparent failure of Company to identify the above enumerated costly risks to ratepayers and the_lack in this or last year's IRPs of any discussion of cost justification, or discussion of risk mitigation associated with these costly risks, the Company's has failed to fulfill its obligation to undertake both least-cost planning as well as to anticipate and plan for mitigating both known and knowable financial risks to ratepayers; as well as for planning for mitigating both known and knowable potential and likely financial risks to ratepayers.

Finally, based on my analysis of the Company's load duration curves, it is my opinion that the Company has sufficient pipeline capacity today to run both its existing and under construction Natural Gas CC units plus one generic Natural Gas CC unit.

Q. Does that conclude your testimony?

A. Yes.

Attachments

1. List of Prior Expert Testimony of Gregory Lander
2. Biography of Gregory Lander
3. Company Response to ER 8-11(b)
4. Company Response to ER 7-3(c)
5. Company Response to Staff 7-92(a)
6. Company Response to Staff 3-31 (Attachment to Staff 3-31 (KS).xlsx)
7. Staff 9-107(f)

Schedule EDF-01: Expert Testimony of Gregory M. Lander

Name of Case	Jurisdiction	Docket Number	Date
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP04-251-000	May 3, 2004 (Testimony)
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP08-426-000	May 19, 2009 (Answering Testimony) June 2, 2010 (Supplemental Answering Testimony)
El Paso Natural Gas Company	Federal Energy Regulatory Commission	RP10-1398-000	June 28, 2011 (Answering Testimony) March 4, 2014 (Answering Testimony)
Petition of Boston Gas Company and Colonial Gas Company, each d/b/a National Grid for Approval by the Department of Public Utilities for a Firm Transportation Contract with Algonquin Gas Transmission Company	Massachusetts Department of Public Utilities	13-157	December 12, 2013 (Direct Testimony)
Petition of Boston Gas Company d/b/a National Grid for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate	Massachusetts Department of Public Utilities	15-34	June 5, 2015 (Direct Testimony)

pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project			
Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project	Massachusetts Department of Public Utilities	15-39	June 5, 2015 (Direct Testimony)
Petition of The Berkshire Gas Company for Approval of a Precedent Agreement with Tennessee Gas Pipeline Company, LLC, pursuant to G.L. c. 164, § 94A	Massachusetts Department of Public Utilities	15-48	June 5, 2015 (Direct Testimony)
Investigation of Parameters for Exercising Authority Pursuant to Maine Energy Cost Reduction Act, 35-A M.R.S.A. Section 1901	Maine Public Utilities Commission	2014-00071	July 11, 2014 (Direct Testimony)
Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 *et seq*.	Virginia Corporation Commission	PUR-2017-00051	August 11, 2017 (Direct Testimony)
In the Matter of the Laclede Gas Company's Request to Increase Its Revenues for Gas	Missouri Public Service Commission	**File No. GR-2017-0215**	September 8, 2017 (Direct Testimony)

Service In the Matter of the Laclede Gas Company d/b/a Missouri Gas Energy's Request to Increase Its Revenues for Gas Service		**File No. GR-2017-0216**	Consolidated and November 21, 2017 (Surrebuttal Testimony) Consolidated
Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019. Application of Southern California Gas Company (U904G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2019.	California Public Utilities Commission	Application 17-10-007 Application 17-10-008	Consolidated Direct Testimony May 14, 2018 Rebuttal Testimony June 8, 2018
Application of Virginia Electric and Power Company to revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia	Virginia State Corporation Commission	PUR-2018-00067	Direct Testimony June 14, 2018
Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) Regarding Feasibility of Incorporating Advanced Meter Data Into the Core Balancing Process	California Public Utilities Commission	Application 17-10-002	Direct Testimony July 2, 2018

SkippingStone

Greg Lander, President
Skipping Stone LLC

Professional Summary:

As President of Skipping Stone Inc., Greg Lander is responsible for Strategic Consulting in the mergers and acquisition arena with numerous clients within the energy industry. Generally recognized in the energy industry as an expert, he has advised and/or given testimony at numerous Federal Energy Regulatory Commission (FERC), State, arbitration, and legal proceedings on behalf of clients and has advised as well as initiated standards formation before the Gas Industry Standards Board (GISB) (predecessor to the North American Energy Standards Board (NAESB)). As Founder, President, and Chief Technology Officer of TransCapacity Limited Partnership, he was responsible for conceiving, planning, managing, and designing Transaction Coordination Systems utilizing Electronic Data Interchange (EDI) between trading partners. As a founding member of GISB, he assisted in establishing protocols and standards within the Business Practices, Interpretations and Triage Subcommittees.

Professional Accomplishments:

- Handled all Due Diligence for purchaser (Loews Corp) in acquisitions of two interstate pipelines, one natural gas storage complex, and ethylene distribution and transmission systems (Texas Gas Transmission, Gulf South Pipeline, Petal Storage, Petrologistics, and Chevron Ethylene Pipeline) most in excess of $1 Billion. Developed purchaser's business case model, including rate/revenue models, forward contract renewal models, export basis modeling and revenue models, and operating cost and capex models. Coordinated Engineering and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.
- Assisted major electric retailer in 9 states with business case development for entry into North Eastern U.S. Commercial &Industrial natural gas marketing business. Identified market share of incumbents; retail registration process, billing processes; utility data exchange rules and procedures and developed estimates of addressable market by utility.
- Handled all economic Due Diligence for purchaser of large minority stake in Southern Star Gas Pipeline. Developed purchaser's business case model, including rate/revenue models and forward contract renewal models, assessed potential competitive by-pass of asset located in "pipeline alley", developed revenue models and operating cost and capex models. Coordinated Engineering, Pipeline Integrity, and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.
- Developed post-acquisition integration plans for inter-operability and alterations to system operations to take advantage of opportunities presented by

synergistic facilities' locations and functions and complimentary contractual requirements. Implementation of plan resulted in fundamental changes to systems operations and improvement in systems, net revenues, capacity capabilities, and facilities utilization.

- Handled all economic analysis, modeling, and systems capability due diligence for potential purchaser in several preliminary or completed yet un-consummated pre-transaction investigations involving Panhandle Eastern, Northern Border, Bear Paw, Florida Gas, Transwestern, Great Lakes, Guardian, Midwestern, Viking, Southern Star, Columbia Gas, Midla, Targa (No. Texas), Ozark, ANR, Falcon Gas Storage, Tres Palacios, Rockies Express, Norse Pipelines, Southern Pines, Leaf River, LDH (Mont Belvieu), Kinder Morgan Interstate, Trailblazer, Rockies Express and South Carolina Gas Transmission.
- Post Texas Gas Transmission and Gulf South Pipe Line acquisitions, assisted with all investigations involving assessments and proposals for realizing potential synergies with/from asset portfolio; rate case strategy development and alternate case development; and strategies around contract renewal challenges.
- Headed up due diligence team in acquisition of multi-state retail (residential) natural gas and electric book by Commerce Energy.
- Headed up due diligence team in acquisition of multi-state retail (C&I) natural gas book by Commerce Energy.
- Served as lead consultant for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in several major FERC Rate Cases, service restructuring, and capacity allocation proceedings involving a major Southwestern U.S. Pipeline.
- Served as lead consultant and expert witness for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in major FERC rate case under litigation involving decades-long disputes over service levels, cost allocation, and rate levels.
- Served as lead consultant for consortium of end-users and municipalities in major FERC rate case involving implementation of proposed rate design, cost allocation, and rate level changes.
- Developed and critiqued Rate Case Models for several pipeline proceedings and proposed proceedings (as consultant variously to both pipeline and shippers). Activities included modeling (and critiquing) new services' rates, costs, and revenues; responsibilities included development of various alternative cost allocation/rate designs and related service delivery scenarios.
- Handled all market assessment, forward basis research, and transportation competition modeling for several proposed major pipelines and laterals, including two $1 Billion+ Greenfields projects that went into construction and operation providing new outlets for growing southwestern shale production. (Gulf Crossing and Fayetteville Lateral).

- Assessed supply and demand balance for Southwestern US (OK, TX, Gulf Coast and LA) including assessment of future demand and supply displacement associated with West Texas wind power development and its likely impact on pipeline export capacity from region.
- Assessed supply and demand balance for Northeast to Gulf Coast capacity additions including assessment of Gulf Coast demand and export growth and its likely impact on forward basis.
- Assessed start-up gas supply needs for Appalachian coal fired power plant, resulting in installation of on-site LNG storage and gasification to address lack of enough firm pipeline capacity to meet need.
- Assessed installed and projected wind-turbine capacity in ERCOT and its eventual impact on Texas electric market as wind power output approaches minimum ERCOT load levels.
- Designed and developed EDI based data collection system, data warehouse and web-based delivery system (www.capacitycenter.com) for delivering capacity data collected from pipelines to shippers, marketers, traders, and others interested in capacity information to support business operations and risk-management requirements.
- Designed pipeline capacity release deal integrating settlement system for firm users, including design and development for information services delivery on a transaction fee basis.
- Assisted client in developing proposals to increase pipeline capacity responsiveness and proposed market fixes that would create price signals around sub-day non-ratable flows, including rate proposals, sub-day capacity release markets, and measures to address advance reservation of capacity for electric generation fuel to meet sub-day generation demands.
- Developed "universal capacity contract" data model for storage of all interstate capacity contract transactions from all 60 major interstates in single database.
- Led design effort culminating in FERC-mandated datasets defining pipeline capacity rights, (including receipt capacity, mainline capacity, delivery capacity, segmentation rights, in and out of path capacity rights), Operationally Available Capacity, Index of Customers, and Transactional Capacity Reports (through GISB).
- Assembled consortium of utilities to investigate and develop large high-deliverability salt storage cavern in desert southwest (Desert Crossing). As LLC's Acting Manager, was responsible for developing business case and economic models; handling all partner issues and reporting; coordinating all field engineering, facilities design, planning and siting; and managing all environmental, legal, engineering and regulatory activities. Wrote FERC Tariff. Brought project to NEPA Pre-Filing Stage and conducted non-binding Open Season, as well as assisted with prospective shipper negotiations. Project

cancelled due to 2001 "California Energy Crisis" and contemporaneous Enron and energy trading sector implosions.

- Designed comprehensive retail energy transaction and customer acquisition data model, process flow, and transaction repository for web-based customer acquisition and customer enrollment intermediary.
- Experienced in negotiation and drafting (from both seller side and buyer side) of firm supply, firm transportation, firm storage, and power supply and capacity agreements for numerous entities including project financed IPPs and for new greenfields pipeline and expansion of storage system.
- Provided market entry assessment for large international manufacturing and service company seeking to enter U.S. micro-grid, combined heat and power, and integrated solar, gas & battery markets.
- Conducted interstate pipeline capacity utilization analysis for New England following winter of 2013/2014 price fly-up.
- Conducted PJM East interstate gas pipeline capacity utilization and comparative analysis between pipelines with standard NAESB nominating cycles versus those with near hourly scheduling practices.
- Conducted requirements analysis for several firms pursuing software selection of energy transaction systems.
- Instrumental in the formation of the GISB. Member of industry team that lead the development of the proposal for and bylaw changes related to the formation of NAESB.
- Provided support to numerous clients and clients' attorneys in disputes involving capacity contracts, capacity rights allocations, tariffs, rate cases, intellectual property rights cases, and supply contract proceedings as both up-front and behind the scenes expert.

Associations and Affiliations:

Longest serving Member of Board of Directors for NAESB and prior to that GISB - ~~20~~ years.

GISB Committees: Former Chairman, Business Practices Subcommittee – drafted approximately 450+ initial industry standards that are now codified FERC regulations (Order 567); Former Chairman, Interpretations Subcommittee – drafted and led adoption process for first 50+ standards interpretations; Former Chairman, Triage Subcommittee; Title Transfer Tracking Task Force; Order 637 GISB Action Subcommittee; and industry Common Codes Subcommittee. Currently member of NAESB Wholesale Gas Quadrant Executive Committee and of NAESB Parliamentary Committee

Past and Affiliations and Associated Accomplishments:

1981-1989: One of five initial employees of Citizens Energy Corporation, Boston Mass. Responsible for starting and growing Citizens Gas Supply, one of the first independent gas marketers of the early 1980's, into $200MM+ annual operation. Successfully lobbied for pipeline Open Access (Orders 436 and 636), introduction of pipeline Affiliated Marketer rules of conduct (Order 497), and Open Access to pipeline operational information (Order 563).

1989-1993: Independent Consultant - Natural Gas Projects, Pipeline Rate Cases, Project Financed Contract negotiations, and Independent Power markets

1993 – 1999: Founder and President, TransCapacity Service Corp – Software products and services related to pipeline capacity trading, nomination, and contracting. Raised $17 MM from industry player to establish TransCapacity. Successfully lobbied for Pipeline restructuring and formation of capacity release market (Order 636). Sold to Skipping Stone.

1999 – 2004: Principal and Partner, Skipping Stone – Energy market consultants

2004 – 2008: President of Skipping Stone following purchase of Skipping Stone by Commerce Energy, Inc.

2008: Repurchased Skipping Stone from Commerce Energy, Reformulated Skipping Stone as LLC with Peter Weigand

2008 to Present: President and Partner, Skipping Stone. In addition to handling book of clients, responsible for all Banking, Accounting, Operations, Risk Management and contract matters for Skipping Stone.

Education:

1977: Hampshire College, Amherst, MA; Bachelor of Arts

Publication:

2013: Synchronizing Gas & Power Markets - Solutions White Paper

Virginia Electric and Power Company
Case No. PUR-2018-00065
Environmental Respondents
Eighth Set

The following response to Question No. 8 of the Eighth Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on July 11, 2018 has been prepared under my supervision.

Ted Fasca

Ted Fasca
Manager – Generation System Planning
Dominion Energy Virginia

The following response to Question No. 8 of the Eighth Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on July 11, 2018 has been prepared under my supervision.

for

Vishwa B. Link
McGuireWoods LLP

Question No. 8

Reference the Company's response to ER Set 3-18, which states "a balanced approach includes the consideration of options for managing and enhancing rate stability, ensuring energy independence, promoting economic development, and incorporating input from stakeholders, will help the Company meet growing demand while protecting customers form a variety of potential negative impacts and challenges."

a) Has the Company performed an analysis of how the Company's precedent agreement on the Atlantic Coast Pipeline helps the Company "manage" rate stability? If so, provide that analysis.

b) Has the Company performed an analysis of how the Company's precedent agreement on the Atlantic Coast Pipeline "enhances" rate stability? If so, provide that analysis.

c) Has the Company performed an analysis of how the Company's precedent agreement on the Atlantic Coast Pipeline to import natural gas from West Virginia "ensures energy independence"? If so, provide that analysis.

Response:

The Company objects to this request as not relevant or reasonably calculated to lead to the production of admissible evidence in this proceeding on the grounds that the availability and/or development of additional interstate natural gas pipeline capacity resources is not the subject of the Plan nor is it an inquiry the Company is required to conduct to develop the subject of the Plan.

Virginia Electric and Power Company
Case No. PUR-2018-00065
Environmental Respondents
Seventh Set

The following response to Question No. 3 of the Seventh Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on July 3, 2018 has been prepared under my supervision.

Teri Fasca
Manager – Generation System Planning
Dominion Energy Virginia

Question No. 3

Request 7-3. Refer to DOM VA's response to ER 3-19 where the Company states "No." *[sic]* The PLEXOS model uses gas commodity prices based on each gas-fired generating resource access to supply points." Please answer the following questions and provide the requested information:

b) Please identify by gas-fired generating resource, the modeled Delivered Price in $/Dth, the access point by name and pipeline, and the modeled supply price by access point, for each month of the planning period.

Response:

(b) See Extraordinarily Sensitive Attachment ER 7-3 (b) (TF), which contains extraordinarily sensitive information (Contract Information) in its entirety, and is being provided pursuant to the protections set forth in 5 VAC 5-20-170 and subject to the Hearing Examiner's Protective Ruling and Additional Protective Treatment for Extraordinarily Sensitive Information entered on May 18, 2018 in Case No. PUR-2018-00065, as modified by Hearing Examiner's Rulings dated June 7, 2018 and June 14, 2018, and any subsequent Protective Order or Ruling that may be issued for confidential or extraordinarily sensitive information in this proceeding, and pursuant to Agreements to Adhere executed pursuant to any such Orders or Rulings.

Virginia Electric and Power Company
Case No. PUR-2018-00065
Virginia State Corporation Commission Staff
Seventh Set

The following response to Question No. 92 (a) of the Seventh Set of Interrogatories and Requests for Production of Documents Propounded by the Virginia State Corporation Commission Staff received on June 11, 2018 has been prepared under my supervision.

Christopher C. Hewett
Supervisor, PJM Energy Settlement &
Demand Response
Virginia Electric and Power Company

Question No. 92

Please provide the following load data for the Dominion LSE as an excel spreadsheet with all formulas intact:

a) Historic hourly load data for Dominion LSE for the period 2014 to present.

Response:

a) The historical hourly load data for Dominion Energy LSE for the period 2014 to present is provided in Attachment Staff Set 7-92(a) (CH). Please note that no load data is available past March 2018 because final settlement is not available until 60 days following the end of the respective month.

Attachment to Staff 3-31 (KS).xlsx
2015 Plan

Zonal Peak Demand (MW)

Year	Winter	Summer
2015	17,369	19,974
2016	17,672	20,487
2017	17,916	20,777
2018	18,064	21,216
2019	18,307	21,749
2020	18,587	22,157
2021	18,854	22,378
2022	19,195	22,626
2023	19,327	22,883
2024	19,457	23,354
2025	19,789	23,666
2026	20,011	23,970
2027	20,329	24,175
2028	20,703	24,344
2029	20,722	24,651
2030	20,977	25,067

LSE Peak Demand (MW) before any DSM reductions

Year	Winter	Summer
2015	14,969	17,475
2016	15,230	17,925
2017	15,441	18,179
2018	15,569	18,563
2019	15,778	19,031
2020	16,020	19,388
2021	16,251	19,582
2022	16,545	19,799
2023	16,659	20,024
2024	16,771	20,437
2025	17,057	20,710
2026	17,250	20,977
2027	17,524	21,156
2028	17,847	21,305
2029	17,863	21,574
2030	18,084	21,938

Zonal Energy (MWh)

Year	Annual
2015	98,610,915
2016	101,617,815
2017	103,144,719
2018	104,809,517
2019	106,208,204
2020	108,016,494
2021	109,098,925
2022	110,578,961
2023	112,047,122
2024	113,783,095
2025	114,919,028
2026	116,357,933
2027	117,822,765
2028	119,624,145
2029	120,812,885
2030	122,176,377

LSE Energy (MWh) before any DSM reductions

Year	Annual
2015	86,386,004
2016	89,026,738
2017	90,369,190
2018	91,830,703
2019	93,059,127
2020	94,644,395
2021	95,596,338
2022	96,895,656
2023	98,184,447
2024	99,706,544
2025	100,705,324
2026	101,968,339
2027	103,254,246
2028	104,833,598
2029	105,878,883
2030	107,075,705

Attachment to Staff 3-31 (KS).xlsx
2016 Plan

Zonal Peak Demand (MW)

Year	Winter	Summer
2016	18,090	20,127
2017	18,418	20,562
2018	18,601	20,995
2019	18,919	21,418
2020	19,192	21,847
2021	19,453	22,263
2022	19,807	22,546
2023	20,005	22,792
2024	20,136	23,260
2025	20,523	23,566
2026	20,776	23,792
2027	21,164	24,016
2028	21,555	24,201
2029	21,588	24,482
2030	21,874	24,919
2031	22,162	25,249

LSE Peak Demand (MW) before any DSM reductions

Year	Winter	Summer
2016	15,612	17,620
2017	15,896	18,001
2018	16,053	18,379
2019	16,328	18,750
2020	16,563	19,125
2021	16,788	19,490
2022	17,094	19,738
2023	17,265	19,952
2024	17,378	20,362
2025	17,712	20,630
2026	17,931	20,828
2027	18,265	21,024
2028	18,603	21,186
2029	18,631	21,432
2030	18,878	21,814
2031	19,127	22,103

Zonal Energy (MWh)

Year	Annual
2016	98,867,586
2017	100,350,600
2018	101,956,210
2019	103,638,487
2020	105,547,819
2021	107,257,694
2022	109,102,526
2023	110,897,263
2024	112,546,305
2025	114,121,953
2026	115,719,660
2027	117,316,592
2028	118,900,366
2029	120,497,198
2030	122,105,835
2031	123,899,542

LSE Energy (MWh) before any DSM reductions

Year	Annual
2016	86,684,220
2017	87,986,035
2018	89,393,640
2019	90,868,776
2020	92,540,891
2021	94,042,310
2022	95,660,142
2023	97,233,692
2024	98,677,848
2025	100,060,913
2026	101,462,481
2027	102,862,755
2028	104,249,852
2029	105,651,684
2030	107,062,486
2031	108,635,619

Attachment to Staff 3-31 (KS).xlsx
2017 Plan

Zonal Peak Demand (MW)

Year	Winter	Summer
2017	17,478	20,014
2018	17,702	20,442
2019	17,959	20,848
2020	18,232	21,208
2021	18,541	21,440
2022	18,932	21,795
2023	19,069	21,957
2024	19,243	22,364
2025	19,470	22,607
2026	19,642	22,888
2027	19,950	23,235
2028	20,245	23,402
2029	20,314	23,694
2030	20,466	24,065
2031	20,704	24,371
2032	20,945	24,681

LSE Peak Demand (MW) before any DSM reductions

Year	Winter	Summer
2017	15,044	17,501
2018	15,236	17,875
2019	15,457	18,230
2020	15,692	18,545
2021	15,958	18,747
2022	16,295	19,058
2023	16,413	19,200
2024	16,563	19,555
2025	16,758	19,768
2026	16,905	20,013
2027	17,171	20,317
2028	17,424	20,463
2029	17,484	20,718
2030	17,615	21,042
2031	17,820	21,310
2032	18,027	21,581

Zonal Energy (MWh)

Year	Annual
2017	99,257,947
2018	100,972,224
2019	102,386,452
2020	103,946,181
2021	105,229,243
2022	107,520,997
2023	108,759,501
2024	110,285,465
2025	111,254,957
2026	112,449,671
2027	113,756,829
2028	115,445,882
2029	116,505,454
2030	117,582,065
2031	119,041,105
2032	120,518,380

LSE Energy (MWh) before any DSM reductions

Year	Annual
2017	86,940,039
2018	88,441,217
2019	89,679,779
2020	91,043,449
2021	92,169,352
2022	94,177,075
2023	95,261,777
2024	96,596,390
2025	97,447,466
2026	98,493,944
2027	99,639,080
2028	101,116,447
2029	102,046,530
2030	102,989,795
2031	104,268,071
2032	105,562,327

Attachment to Staff 3-31 (KS).xlsx
2018 Plan

Zonal Peak Demand (MW)

Year	Winter	Summer
2018	18,666	19,938
2019	18,974	20,282
2020	19,291	20,568
2021	19,748	20,867
2022	20,191	21,161
2023	20,517	21,477
2024	20,862	22,010
2025	21,175	22,381
2026	21,534	22,757
2027	22,024	23,006
2028	22,394	23,228
2029	22,537	23,567
2030	22,696	23,960
2031	22,935	24,230
2032	23,161	24,422
2033	23,608	24,610

LSE Peak Demand (MW) before any DSM reductions

Year	Winter	Summer
2018	16,019	17,417
2019	16,283	17,718
2020	16,555	17,968
2021	16,947	18,229
2022	17,328	18,486
2023	17,607	18,762
2024	17,904	19,227
2025	18,172	19,551
2026	18,480	19,880
2027	18,901	20,097
2028	19,218	20,292
2029	19,341	20,587
2030	19,477	20,931
2031	19,682	21,167
2032	19,876	21,334
2033	20,260	21,499

Zonal Energy (MWh)

Year	Annual
2018	100,808,907
2019	102,300,136
2020	103,775,877
2021	105,331,462
2022	107,059,853
2023	108,813,922
2024	110,882,650
2025	112,457,008
2026	114,293,786
2027	116,024,848
2028	118,013,726
2029	119,286,564
2030	120,701,635
2031	122,203,981
2032	124,001,371
2033	124,944,836

LSE Energy (MWh) before any DSM reductions

Year	Annual
2018	88,148,095
2019	89,451,104
2020	90,738,445
2021	92,100,640
2022	93,611,295
2023	95,144,326
2024	96,950,823
2025	98,328,935
2026	99,934,689
2027	101,448,275
2028	103,185,105
2029	104,300,158
2030	105,537,663
2031	106,851,106
2032	108,420,559
2033	109,248,032

(11) When used with respect to information, "identify" means to state the information requested.

(12) For each document or other requested information asserted to be privileged or otherwise excludable from discovery, identify the document or information and the basis, citing legal authority, for such claim of privilege or other ground for exclusion.

(13) Whenever the Company is requested to give specific information, such as a date or a figure, and the Company cannot give the exact information, the Company must provide its best estimate thereof.

STAFF INTERROGATORIES AND DOCUMENT REQUESTS

(107 - **corrected)** The Commission has the constitutional and statutory duty to ensure that Virginians receive a reliable supply of electricity at just and reasonable rates. As such, it is important that an IRP address both system reliability and costs. Please answer the following questions with regard to system reliability.

(a) Please refer to the 2014 "Polar Vortex" weather event. Please provide the following data for the period January 1, 2014 through January 8, 2014:

(1) For each of the Company's coal units, provide actual hourly energy output beginning at 12 a.m. January 1, 2014 through 12 a.m. January 8, 2014.

(2) For the Plymouth Solar Facility, please provide actual hourly energy output beginning at 12 a.m. January 1, 2014 through 12 a.m. January 8, 2014.

(3) Please provide the hourly capacity import availability from the PJM market beginning at 12 a.m. January 1, 2014 through 12 a.m. January 8, 2014.

(4) Please provide the actual amount of energy purchased from the PJM market for each hour beginning at 12 a.m. January 1, 2014 through 12 a.m. January 8, 2014.

(b) Please refer to the 2018 "Bomb Cyclone" weather event. Please provide the following data for the period January 1, 2018 through January 7, 2018:

(1) For each of the Company's coal units, please provide actual hourly energy output beginning at 12 a.m. January 1, 2018 through 12 a.m. January 7, 2018.

(2) For each of the Company Owned Solar Facilities (Morgan's Corner, Whitehouse, Scott, and Woodland), please provide actual hourly energy output beginning at 12 a.m. January 1, 2018 through 12 a.m. January 7, 2018.

(3) Please provide the hourly capacity import availability from the PJM market beginning at 12 a.m. January 1, 2018 through 12 a.m. January 7, 2018.

(4) Please provide the actual amount of energy purchased from the PJM market for each hour beginning at 12 a.m. January 1, 2018 through 12 a.m. January 7, 2018.

(c) Did the Company perform any type of "Stress Test" analyses to determine the potential impacts of placing the Company's coal units in cold storage (mothballed) status on system reliability during significant weather events similar to the 2014 Polar Vortex or 2018 Bomb Cyclone (assuming limited capacity import capability from PJM) prior to making the decision to place the Company's coal units into cold storage (mothballed) status? If so, please provide these analyses.

(d) Does the Company believe that the resources selected by the PLEXOS model for each of the Plans A through E, which are comprised primarily of intermittent solar resources and gas-fired combustion turbine units with interruptible gas supply service and three days of back-up fuel, adequately maintains the system reliability lost when the Company's coal units are placed into cold storage (mothballed) status? If so, please provide the analysis showing that system reliability is adequately maintained.

(e) Did the Company investigate whether back-up fuel capability should be added to its Brunswick, Warren County, and Greensville gas-fired combined cycle units as a result of the decision to place the Company's coal units into cold storage (mothballed) status? If not, please explain why the Company does not feel that this is necessary.

(f) Please estimate the cost of adding a 30-day back-up fuel capability at the Company's Brunswick, Warren County, and Greensville gas-fired combined cycle units.

CERTIFICATE OF SERVICE

I hereby certify that the following have been served with a true and accurate copy of the foregoing via first-class mail, postage pre-paid:

Ashley B. Macko
Garland S. Carr
Kiva Bland Pierce
Office of General Counsel
STATE CORPORATION COMMISSION
P.O. Box 1197
Richmond, VA 23218

C. Meade Browder, Jr.
Cody Murphey
Division of Consumer Counsel
OFFICE OF THE ATTORNEY GENERAL
202 North Ninth St, 8th Floor
Richmond, VA 23219

Louis R. Monacell
Edward L. Petrini
James G. Ritter
CHRISTIAN & BARTON, LLP
909 East Main St, Ste 1200
Richmond, VA 23219

Eric W. Hurlocker
William T. Reisinger
Eric J. Wallace
GREENEHURLOCKER, PLC
1807 Libbie Avenue, Ste 102
Richmond, VA 23219

Bobbi Jo Alexis
CULPEPER COUNTY, VIRGINIA
306 North Main St
Culpeper, VA 22701

Lisa S. Booth
Audrey T. Bauhan
DOMINION ENERGY SERVICES
120 Tredegar Street, RS-2
Richmond, VA 23219

Vishwa B. Link
Jennifer D. Valaika
Sarah R. Bennett
MCGUIRE WOODS, LLP
Gateway Plaza
800 East Canal Street
Richmond, VA 23219

Evan D. Johns
APPALACHIAN MOUNTAIN ADVOCATES
415 Seventh Street NE
Charlottesville, VA 22902

Robert D. Perrow
WILLIAMS MULLEN
200 South 10th St, Ste 1600
Richmond, VA 23219

Robert F. Riley
Bradley J. Nowak
WILLIAMS MULLEN
1666 K St Northwest, Ste 1200
Washington, DC 2006

Michael J. Coughlin
WALSH COLUCCI LUBELEY & WALSH
4310 Prince William Parkway, Ste 300
Prince William, VA 22192

Dorothy E. Jaffe
SIERRA CLUB
50 F St NW, 8th Floor
Washington, DC 20001

Bruce H. Burcat
MID-ATLANTIC RENEWABLE ENERGY COALITION
29 North State St, 3rd Floor, Ste 300
Dover, DE 19901

Maggie Clark
State Affairs Senior Manager, Southeast
SOLAR ENERGY INDUSTRIES ASSOCIATION
600 14th Street, NW, Ste 400
Washington, DC 20005

William C. Cleveland
SOUTHERN ENVIRONMENTAL LAW CENTER

DATED: August 10, 2018

Virginia Electric and Power Company
Case No. PUR-2017-00051
Environmental Respondents
Sixth Set

The following response to Question No. 20 of the Sixth Set of Interrogatories and Requests for Production of Documents Propounded by the Environmental Respondents received on July 25, 2017 has been prepared under my supervision.

Ted Fasca

Ted Fasca
Advisor - Generation System Planning
Virginia Electric and Power Company

Question No. 20

Reference the Company's response to ER Set 2-33.

a) Has the Company performed an analysis in this IRP of whether it can meet its service obligations without using natural gas from the Atlantic Coast Pipeline (regardless of whether the Company's generating assets perform at the same capacity factors as those identified in this year's IRP)?

b) If not, please explain why.

c) If so, please provide that analysis.

d) Does the Company contend that it cannot meet its service obligations without the Atlantic Coast Pipeline?

e) Does the Company contend that it can meet its service obligations without the Atlantic Coast Pipeline but only by increasing costs to its customers?

Response:

(a)–(c) No, the Company did not perform such an analysis for purposes of this or any prior Plan analysis. The Company's objective in the 2017 Plan is to identify a mix of resources necessary to meet its customers' projected energy and capacity needs in an efficient and reliable manner at the lowest reasonable cost, while considering future uncertainties. The Company's options for meeting these future needs are: i) supply-side resources, ii) demand-side resources, and iii) market purchases. A balanced approach, which includes the consideration of options for maintaining and enhancing rate stability, energy independence, economic development, as well as input from stakeholders, will help the Company meet growing demand while protecting customers from a variety of potential negative impacts and challenges.

(d)-(e) The Company objects to this request as not relevant or reasonably calculated to lead to the production of admissible evidence in this Integrated Resource Plan proceeding on the grounds that the availability and/or development of additional interstate natural gas pipeline capacity resources is not the subject of the Plan, as discussed in the response to subparts (a)-(c) above. Notwithstanding and subject to the foregoing objections, the Company provides the following response.

Natural gas is largely delivered on a just-in-time basis. Current interruptions on any single pipeline are manageable, but as the Company and the electric industry shift to a heavier reliance on natural gas, additional actions, including securing additional firm natural gas pipeline transportation service, are needed to ensure future system reliability and rate stability for customers.

ACP is a geographically diverse pipeline that will provide access to competitively-priced, domestic natural gas supply and will deliver those supplies to strategic points in the Company's service territory. After ACP is completed, it will provide access to natural gas supply basin (Marcellus and Utica) trading hubs such as South Point which historically have exhibited lower price and price volatility than trading hubs in Virginia (see 2017 Plan pages 133-135). The incremental capacity provided by ACP will support a portion of the natural gas needs for the Company's existing power generation with enhanced fueling flexibility and reliability. ACP will also allow for future, lower-cost pipeline capacity expansions with limited environmental impact.

The Economic Impacts of the Atlantic Coast Pipeline

Prepared for

Dominion Transmission, Inc.

Prepared by

ICF International
9300 Lee Highway
Fairfax, VA 22031

1331 Lamar, Suite 660
Houston, TX 77010

February 9, 2015

Disclaimer

This report reflects ICF's opinion and best judgment based upon the information available to it at the time of its preparation.

ICF's opinions are based upon historical relationships and expectations that ICF believes are reasonable. Some of the underlying assumptions, including those detailed explicitly or implicitly in this report, may not materialize because of unanticipated events and circumstances.

ICF's opinions could, and would, vary materially, should any of the above assumptions prove to be inaccurate.

Table of Contents

Introduction

Dominion Transmission, Inc. (Dominion) engaged ICF International (ICF) to provide an independent assessment of the Atlantic Coast Pipeline (ACP)'s impacts on market area natural gas and electric prices, as well as the impacts on regional economies.

Dominion and its partners[1] have proposed ACP to serve the growing need for natural gas in Virginia and North Carolina, enhance the reliable delivery of natural gas supplies, and expand consumer access to supplies from the neighboring states where the burgeoning Marcellus and Utica shale plays are located.[2] ACP will also provide connections with other supply sources, both shale and non-shale, transiting its Appalachian origin. These multiple supply sources, in the aggregate, have the potential to lower supply costs for ACP market area shippers and their customers. The pipeline will also deliver natural gas to serve consumers in regions of Virginia and North Carolina that are, at present, remote from existing infrastructure. [3]

As shown in Exhibit 1, ACP is planned as a 1.5 billion cubic feet per day (Bcf/d) pipeline[4] that will significantly expand access to gas supplies from the Appalachian Basin in West Virginia, southwest Pennsylvania, and eastern Ohio to natural gas utilities and power plants in Virginia and North Carolina.[5] Virginia and North Carolina have historically been supplied by gas supplies delivered on pipelines originating in the US Gulf Coast, augmented by pipelines transporting supplies produced in the Appalachian Basin, which now includes the additional sources produced from the Marcellus and Utica shale plays. Power plant operators and gas utilities serving Virginia and North Carolina have already subscribed to nearly 91 percent of ACP's capacity.

[1] The announced partners include Duke Energy, Piedmont Natural Gas and AGL Resources.

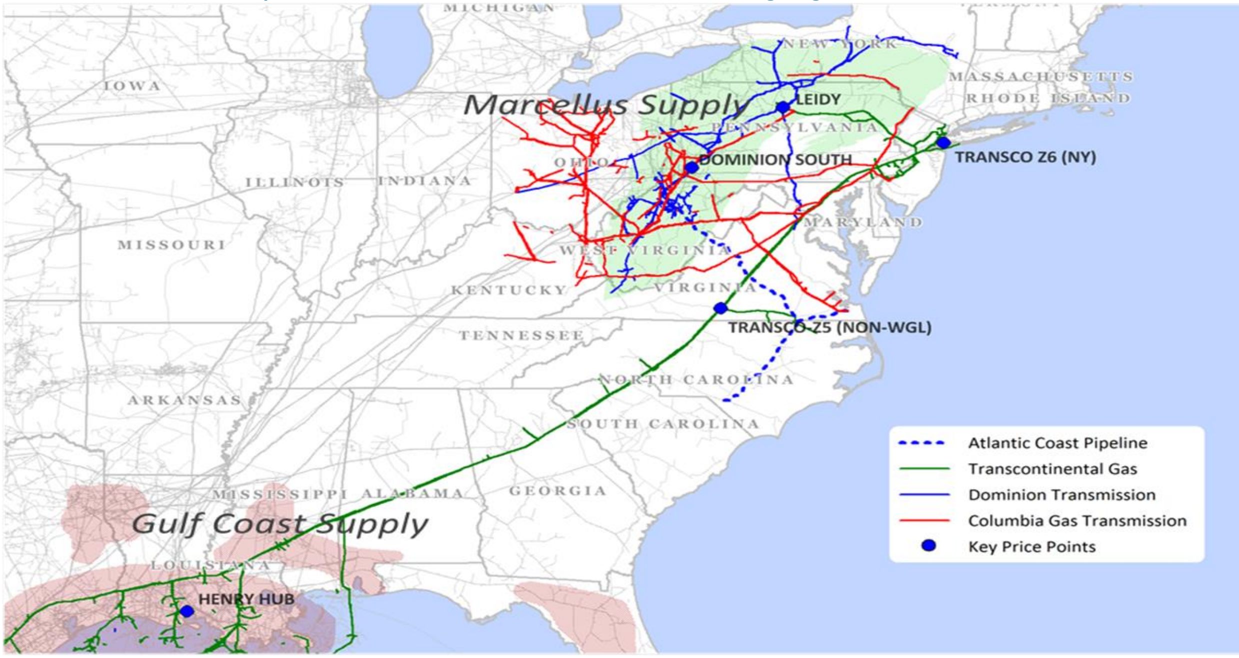
[2] https://www.dom.com/corporate/what-we-do/natural-gas/atlantic-coast-pipeline

[3] Ibid.

[4] For context, a 1000 megawatt (MW) natural gas-fired power plant can consume about .2 Bcf/d of natural gas in full operation. 1000 MW is a common size capacity for such power plants, although plants can be larger or smaller. In gas heating, .1 Bcf/d would heat approximately 400,000 average-size homes.

[5] https://www.dom.com/corporate/what-we-do/natural-gas/atlantic-coast-pipeline

Exhibit 1: Atlantic Coast Pipeline and Other Natural Gas Infrastructure Serving Virginia and North Carolina



Source: ICF, Ventyx

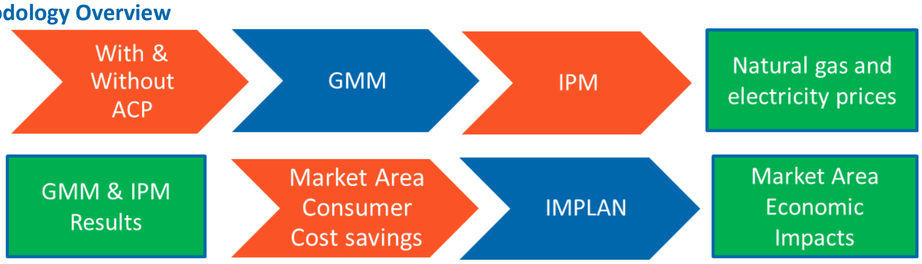
Economic Assessment Overview

This report summarizes ICF's analysis of ACP's potential energy cost savings to natural gas and electricity consumers in Virginia and North Carolina and the related economic impacts to the state economies. ICF's analysis focuses on the 20-year period (2019 – 2038) following the proposed ACP in-service date in November 2018.

ICF's analyses and findings draw from years of experience consulting on North American natural gas and electric markets, and proprietary software tools and databases developed for that purpose. For this study, ICF utilized its Gas Market Model ("GMM") and Integrated Planning Model ("IPM") to model the North American gas and electric markets with and without ACP. ACP's market impacts and consumer cost savings are estimated based on the projected changes in natural gas and wholesale electric prices and electric production costs that result from adding the pipeline to the interstate transportation grid.

The market area's consumer cost savings are inputs to the IMPLAN model. IMPLAN is a sophisticated modeling software that estimates economic activity resulting from various stimuli. It is widely used to understand the impact of energy infrastructure investments on market area economies. ICF's general analysis process is illustrated in Exhibit 2.

Exhibit 2: Methodology Overview



Source: ICF

Key Findings of ICF's Analysis

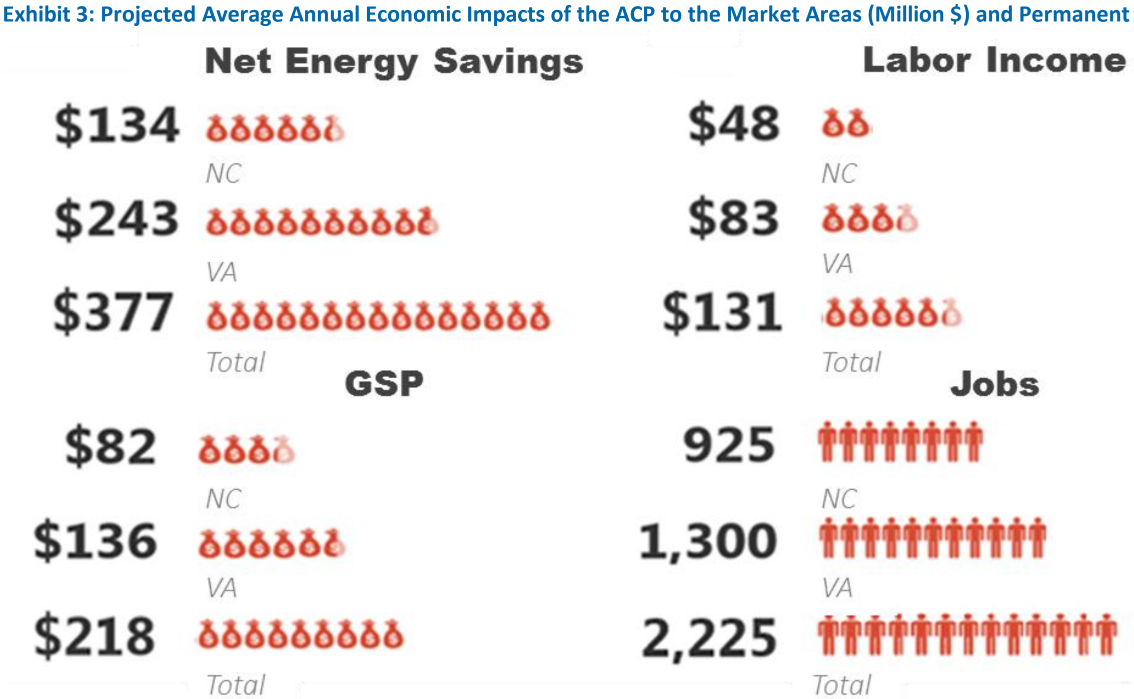
ACP provides significant financial and economic benefits to the North Carolina and Virginia markets.

Between 2019 and 2038, ICF estimates a net annual average energy cost savings of over $377 million dollars - $243 million in Virginia, and $134 million in North Carolina. These benefits accrue to both natural gas and electric consumers and add to the construction and local tax benefits identified in other studies.[6]

These consumer cost savings to households and businesses in Virginia and North Carolina will also trigger stimulus effects that create jobs, boost labor income, and grow the state economies. On average, ICF estimates that economic activity related to ACP enabled energy cost savings will contribute more than 2,200 permanent full-time jobs, $131 million in annual labor income, and $218 million in annual gross state product (GSP) to the two states over the 20-year period.

In addition to these measurable financial benefits, ACP creates significant value by enhancing gas supply security, increasing gas supply flexibility and optionality, improving electric reliability, and supporting renewable generation in its market areas. Exhibit 3 summarizes ACP's economic impacts to Virginia and North Carolina markets.

Exhibit 3: Projected Average Annual Economic Impacts of the ACP to the Market Areas (Million $) and Permanent Jobs



Source: ICF

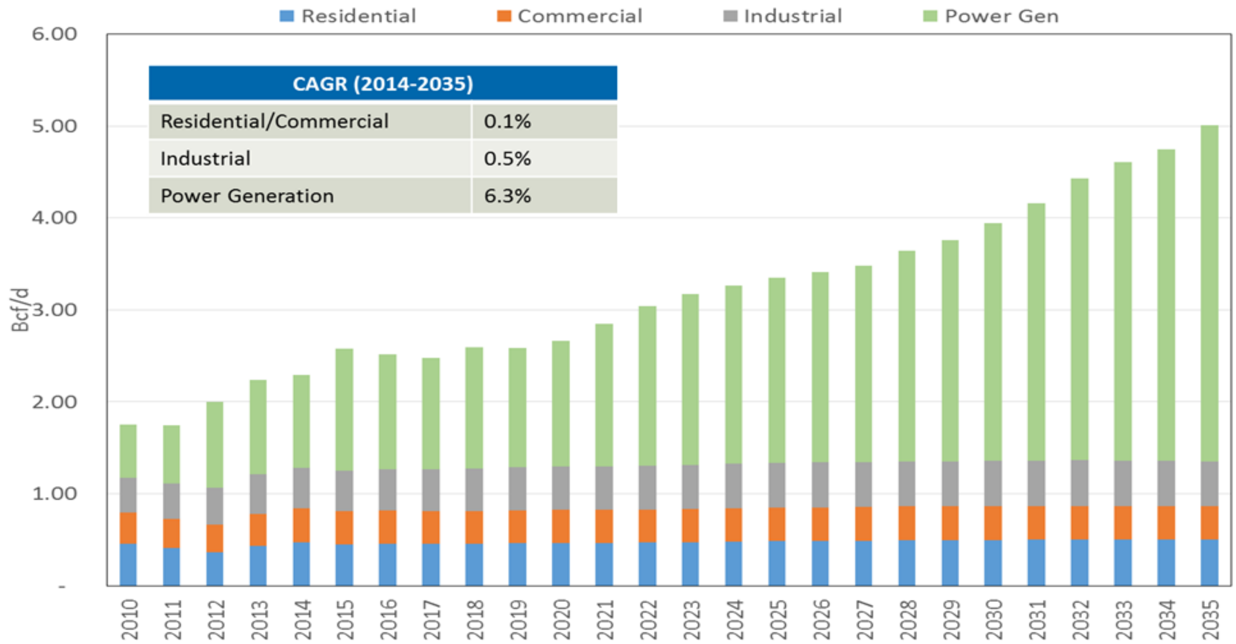
[6] https://www.dom.com/library/domcom/pdfs/gas-transmission/atlantic-coast-pipeline/acp-chmura-report-091014.pdf

Demand and Supply Outlook

ACP is driven by rapid demand growth in Virginia and North Carolina

Over the next 20 years, Virginia and North Carolina electric power generation will increasingly rely on natural gas as the primary fuel source, as the states move away from coal and nuclear energy. During this period, ICF projects that 9,900 MW of coal and nuclear-based capacity – nearly 18 percent of the regional fleet – will be retired, while 20,200 MW of natural gas-fired combined cycle capacity will be constructed.[7] Power sector demand for natural gas is expected to grow at a rapid rate of 6.3 percent annually between 2014 and 2035, nearly quadrupling from the current level of 1 Bcf/d to 3.7 Bcf/d.

Exhibit 4: ACP Market Area Natural Gas Demand Forecast



Source: ICF

The winter of 2013-2014 highlights a need for infrastructure development to support the growth from the electric sector

Located in the middle of the natural gas transportation system, with no regional underground storage facilities, Virginia and North Carolina rely on natural gas delivered on long-haul interstate pipelines such as TransContinental Gas Pipeline (Transco), Columbia Gas Transmission (TCO), and Dominion Transmission (Dominion). The primary supply source to the Virginia and North Carolina markets is the Gulf Coast, with Dominion and TCO providing limited access to the Marcellus/Utica supply.

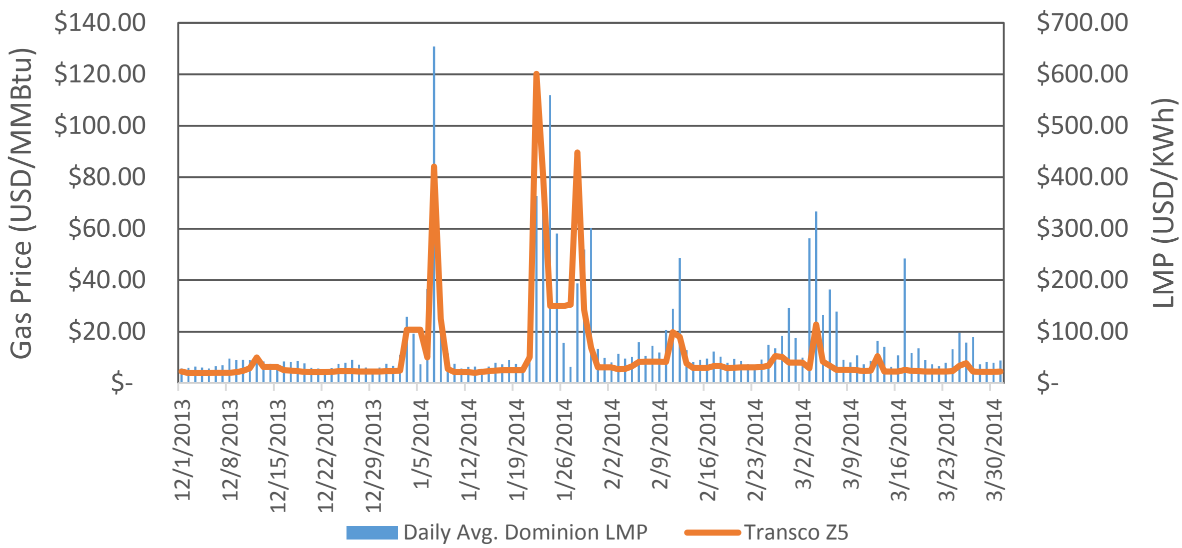
During the severe cold-weather of the 2013-2014 "Polar Vortex" winter, power generation and heating demand for natural gas soared in the Midwest, Northeast, and Mid-Atlantic. Extreme electricity price spikes and volatility, caused by tight natural gas supplies and heavy pipeline utilization, imposed significant economic costs to electric consumers in Virginia and North Carolina. Regional natural gas prices soared to unprecedented levels, exceeding \$120/MMBtu on January 22, while wholesale power prices in

[7] The construction of ACP actually accelerates the migration from coal/nuclear to natural gas because of the cost reductions it drives in natural gas fuel costs.

the Dominion Service territory (driven by surging gas prices) reached $364/MWh on the same day. Power prices, at one point, exceeded $650/MWh, on a day with gas price over $80/MMbtu.[8]

Exhibit 5 illustrates the close historical relationship between delivered natural gas and power prices in Virginia from December 2013 through March 2014. During this time, the wholesale power costs for the Dominion Service territory totaled over $3.3 billion, $2.1 billion higher than the same period in the previous year, when gas prices were much lower. By providing increased capacity and greater supply access to these markets, ICF expects that ACP will help reduce the region's susceptibility to such gas and electric spikes.

Exhibit 5: Winter 2013-2014 Gas and Power Price Relationship



Source: ICF, SNL

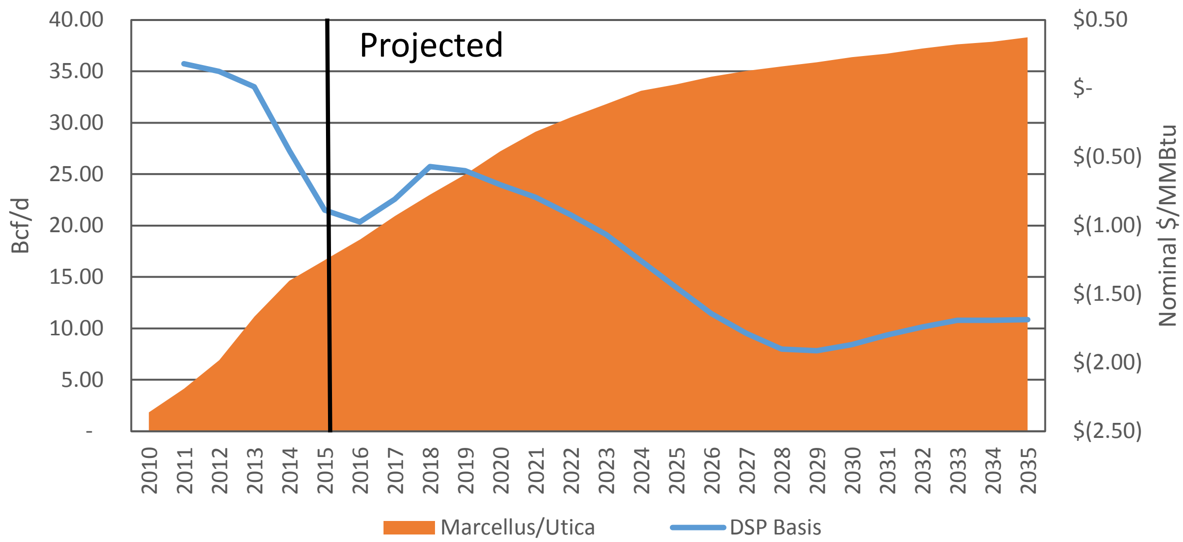
ACP provides access to a robust and economic supply source

The Appalachian Basin was one of the first US oil and gas producing regions, and it continues to provide a significant share of natural gas consumed in east coast and Appalachian states. ICF expects that the Appalachian Basin's role as a major supply source will continue to grow as Marcellus/Utica production increases from its current output of 17 Bcf/d to a projected 38 Bcf/d by 2035, as shown on the left axis of Exhibit 6.

The dramatic increase in low-cost Appalachian Basin gas production has materially altered the relationship of the region's gas prices to other trading points across the North American market. As shown in the right axis of Exhibit 6, the price of natural gas in the Appalachian Basin (represented by the "Dominion South" pricing point) relative to the North American benchmark Henry Hub (Louisiana) price has plummeted nearly $1.50/MMbtu from a premium to a discount of $1.00/MMBtu. ICF projections show the discounted spread to widen further, to more than $1.50/MMBtu. At these prices, the Appalachian Basin is among the lowest gas supply sources on the continent.

[8] Regional spot gas prices for North Carolina and Virginia are reported in industry trade publications as "Transco Zone 5."

Exhibit 6: Historical and Projected Marcellus/Utica Production and Dominion South Point to Henry Hub Basis[9]



Source: ICF

ACP greatly enhances supply security to Virginia and North Carolina consumers

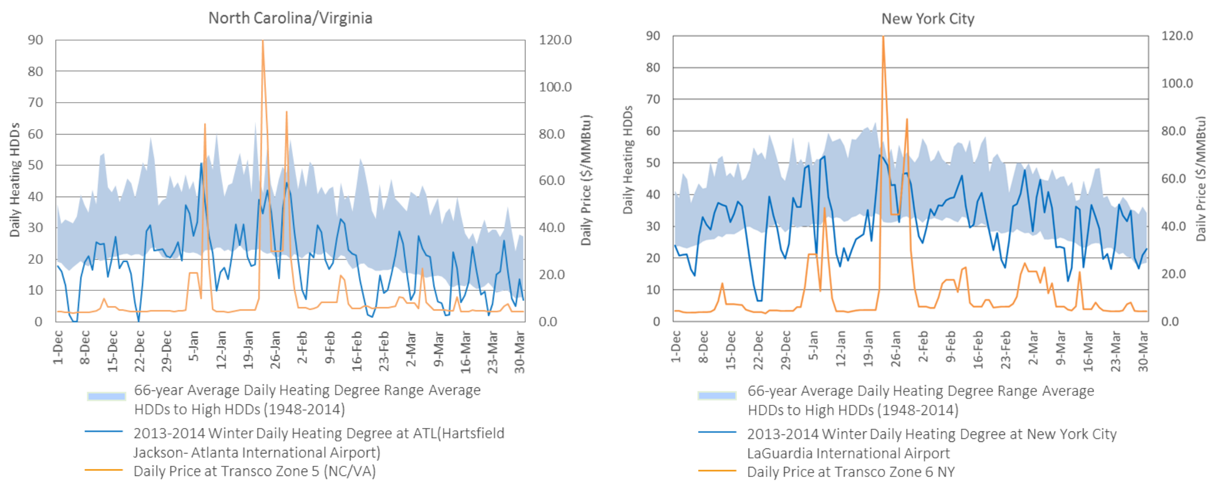
The three large interstate pipelines that serve the ACP market are becoming increasingly congested as demand in the region grows. Firm transportation capacity on each pipeline is near fully contracted and heavily utilized, particularly during peak winter conditions. This means that there is little redundancy in the grid for supply or operating disruptions. Although extremely rare, degradations in service capabilities are events that utilities and their suppliers strive diligently to prevent. ACP introduces new capacity and access to supply that diversifies utilities' natural gas supply portfolio which, in turn, contributes to supply security. Consequently, if supply from one source becomes disrupted, regional needs can still be met with alternative supply sources.

The ACP route also provides utilities with valuable geographic operating benefits. Much of the ACP rights-of-way traverse areas of Virginia and North Carolina that do not have high pressure interstate pipelines; instead, they rely on a network of delivery laterals and local distribution company systems. For gas-fired power plant operators in particular, it is imperative that gas pipelines deliver at high pressures to enable gas turbines to run efficiently. ACP's large-diameter, high-pressure system could enhance the service quality and operational flexibility required by end users.

By adding new gas delivery capacity into the region, ICF has found that ACP helps mitigate the competition and price pressure that market conditions in other areas of the country impose on gas supplies serving Virginia and North Carolina consumers. As shown in Exhibit 7, moderately colder-than-normal weather conditions in the ACP markets, represented by the blue line of 2013-2014 heating degree days[10] (HDDs) positioned mostly in the middle of the blue historical range in the left chart, caused prices in the region to reach unprecedented highs of $80-$120/MMBtu. This was due, in part, to the strong demand-pull and price spikes in the New York City market, reflected in the right chart by the blue HDD line reaching the maximum of the historical range periodically.

[9] Basis presented here is Dominion South Point price minus Henry Hub price.
[10] HDD is calculated as 65 minus the average daily temperature.

Exhibit 7: Weather Conditions and Daily Gas Prices in New York and ACP Market Area



Source: ICF, SNL, NOAA

In addition, ACP allows Virginia and North Carolina customers to benefit from access to the abundant natural gas storage fields located in West Virginia, Ohio, and Pennsylvania. The added supply flexibility that these storage assets provide may also help Virginia and North Carolina avoid costly energy market spikes, like those seen last winter.

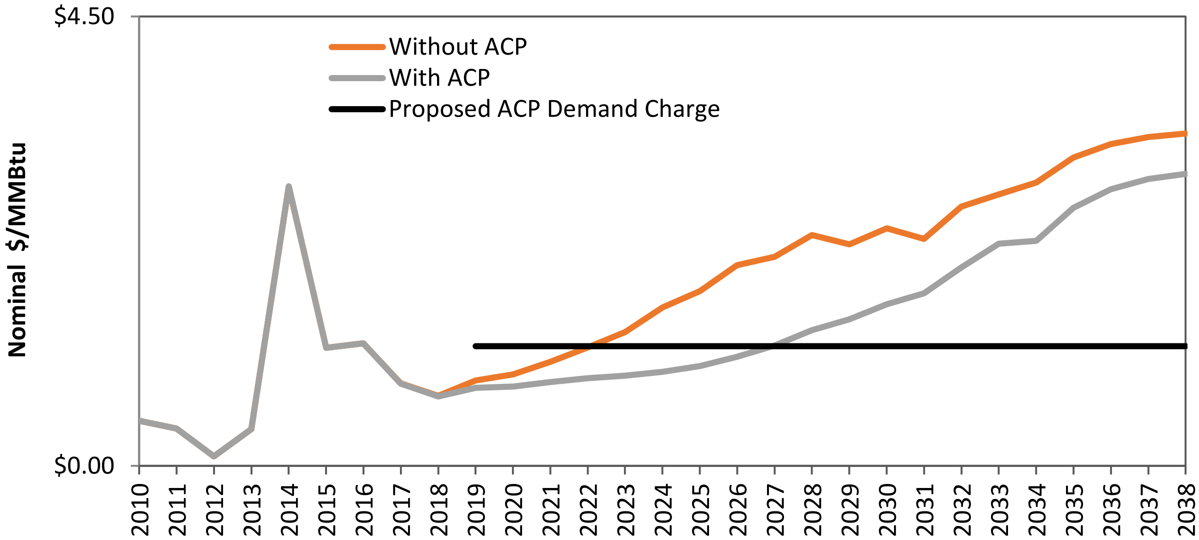
Energy Cost Savings

Natural Gas Market Impact

ACP allows Virginia and North Carolina gas buyers (and their customers) to acquire supplies at Appalachian Basin trading points and transport those supplies to market, rather than purchasing supplies at delivered market pricing points. The cost savings to ACP shippers could be substantial.

As seen in Exhibit 8, ICF estimates that, as compared to purchasing gas supplies delivered into the market, ACP gas buyers could save $1.61/MMBtu on average by transporting Appalachian Basin gas on ACP - far exceeding the proposed transportation rate on the pipeline. The cost savings enabled by the ACP occur early in the life of the project and grow steadily over time.

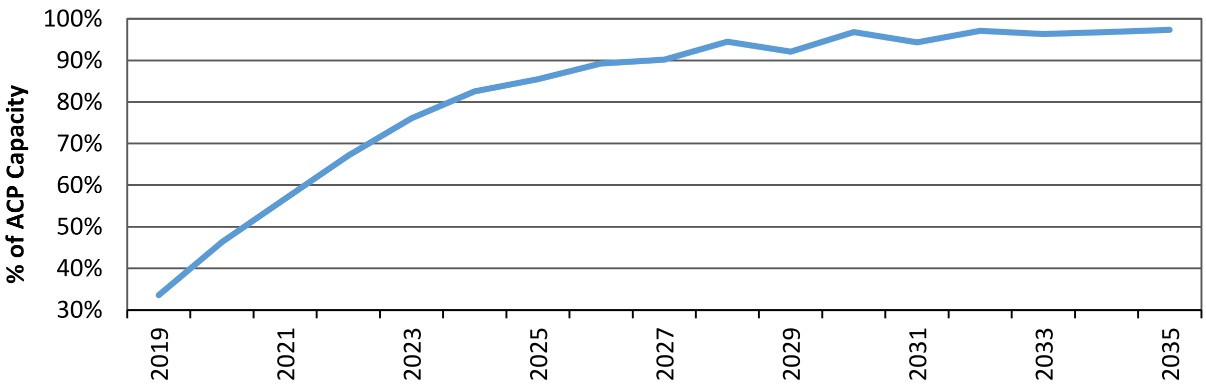
Exhibit 8: Historical and Projected Price Spread between Transco Z5 and Dominion South Point



Source: ICF

Once ACP is placed in service, ICF projects that the market will quickly absorb ACP capacity, as shown on Exhibit 9, with annual average utilization rising to upwards of 80 percent within five years. This is an indication that ACP is an economic and competitive supply source to serve Virginia and North Carolina.

Exhibit 9: Projected ACP Utilization Factor



Source: ICF

Residential, Commercial and Industrial Market Impacts

A small percentage of residential, commercial and industrial (RCI) gas users that purchase gas directly from the regional delivered market will save money with ACP.[11] Exhibit 10 summarizes ICF's estimate of annual savings for these customer classes for the analysis period. The cost savings shown in Exhibit 10 reflect only the benefits of reduced local prices resulting from ACP, and do not include potential cost savings that could result from LDCs re-aligning their supply portfolios to the more economic Appalachian Basin supplies, which will be delivered by ACP, as noted in Exhibit 8.

[11] These are typically larger industrial gas customers that purchase large volumes of gas directly in the local wholesale market, then arrange to have the gas delivered using LDC transportation services.

Exhibit 10: Projected Average Annual Natural Gas RCI Savings from ACP ($Million/Year)

	Average Residential Cost Savings	Average Commercial Cost Savings	Average Industrial Cost Savings	Total Across Sectors
VA	1.3	0.9	4.8	7.0
NC	1.6	1.0	18.8	21.4
Total	**2.9**	**1.9**	**23.6**	**28.4**

Source: ICF

Electric Market Impact

Virginia and North Carolina electricity consumers benefit from ACP because the lower cost of natural gas to fuel power generation will, in turn, result in lower electricity bills for consumers. Owing to differences in electric market structures and operations in Virginia and North Carolina, ICF adopted distinct approaches for estimating the electricity cost savings in each state.

For purposes of this analysis, cost savings to Virginia consumers were calculated assuming that Virginia operates as a competitive market, given that the majority of the generators in the state are participants in PJM. This assumes unregulated utilities base retail rates on the costs of purchasing energy at wholesale prices and other firm/bilateral contractual arrangements. The power generators who bid into the wholesale energy market do not take into account any fixed costs.

Under this type of market structure, each MWh of electricity consumed in Virginia will benefit from a lower Virginia natural gas price because it translates into lower wholesale power prices. ICF estimated consumer cost savings as the retail rate impact based on the projected reduction ACP triggered in wholesale electric market prices and the overall expected retail load.

ICF estimates that ACP will lower annual average wholesale electricity prices by $0.94/MWh, a 1.4 percent reduction for the analysis period. This reduction translates into an annual savings of $236 million a year for Virginia consumers.

In contrast to Virginia, North Carolina is expected to continue operating as a regulated market through the analysis period, whereby customer bills are closely related to the production costs of energy. The total production costs are calculated based on the future total expenditures needed to meet load, which include variable and fixed O&M costs, fuel costs, capital expenditures, and costs of imports.

ICF has determined that ACP makes it possible for electric utilities to acquire and transport lower cost Appalachian Basin supplies on ACP, rather than purchase gas in the regional market. Utilities could pass along the cost savings (net of the pipeline transportation costs) directly to the consumers. This fuel cost reduction results in significant consumer savings. In all, based on ICF's study, ACP could yield net annual cost savings of $113 million for North Carolina electric customers.

Total Consumer Cost Savings

ACP can produce significant energy cost savings to consumers in Virginia and North Carolina. As summarized in Exhibit 11, ICF estimates that ACP will produce an average of $377 million in annual consumer cost savings for the 20-year analysis period. These sums are net of the cost of constructing and operating the pipeline.

Exhibit 11: Projected Annual Average ACP Market Area Net Energy Cost Savings ($ Million/Year)

	VA	NC	Total
Net RCI Gas Cost Savings	7	21	28
Net Electric Cost Savings	236	113	349
Total Net Consumer Savings	**243**	**134**	**377**

Source: ICF

Market Area Economic Impacts

The market area economic impacts measure the effect of net energy cost savings for households and businesses in Virginia and North Carolina on the states' respective economies. In general, energy cost savings allow consumers to spend more money in other sectors of the economy, which stimulates new job creation, labor income, tax revenues and gross state product.

ICF utilized the IMPLAN model to estimate the following types of economic impact on the economy resulting from reductions in the costs of energy:

- Direct – representing the impacts (e.g., employment or economic output changes) due to the direct changes being modeled, such as the higher demand for goods and services for the directly affected sectors which benefit from the additional spending prompted by reduced energy costs;
- Indirect – representing the impacts due to the industry inter-linkages caused by the iteration of directly impacted industries purchasing from other industries, commonly referred to as the "upstream" impacts; and
- Induced – representing the impacts on all local industries due to consumers' consumption expenditures arising from the new household incomes that are generated by the direct and indirect impacts.

ICF reports three key metrics from the economic analysis:

- Total Value Added/Gross State Product – representing the commonly used metric for measuring economic output for a given scenario. It comprises a "catch-all" for payments made by individual industry sectors to workers, interests, profits, and indirect business taxes;
- Employment/Jobs – representing the jobs created by industry, based on the output per worker and output impacts for each industry; and
- Labor Income – representing part of the value added, and consists of all forms of employment income. Consistent with input-output economic terminology, IMPLAN defines this as the sum of employee compensation and proprietors' income.

Exhibit 12 summarizes total economic impacts due to reduced energy costs in Virginia and North Carolina.

ACP could support the creation of more than 2,200 permanent, full-time jobs across the two states, with 1,300 jobs in Virginia and 900 jobs in North Carolina. Most of these jobs are in service sectors, including wholesale/retail establishments, driven mainly by large energy savings for the commercial sector and increased residential consumption expenditures. These jobs are well-paid full-time positions that offer an average annual wage of nearly $64,000 in Virginia and $52,000 in North Carolina.

Over the entire 20-year modeling period, ACP could support close to 45,000 job-years[12] paying Virginia and North Carolina workers over $2.6 billion in wages and salaries. ACP adds $130 million per year and $80 million per year to the VA and NC economies, respectively, yielding incremental tax revenues of $14 million and $9 million per year. Of this, roughly 30 to 40 percent is from property taxes, and 45 to 55 percent is from sales and state income taxes.

Exhibit 12: Projected Market Area Economic Impact Due to Reduced Energy Costs

	Average Annual Impact				20-year Cumulative Impact			
	Jobs	Tax Revenue ($ million)	Labor Income ($ million)	Gross State Product ($ million)	Job-years	Tax Revenue ($ million)	Labor Income ($ million)	Gross State Product ($ million)
North Carolina	925	$9	$48	$82	18,565	$180	$968	$1,648
Virginia	1,300	$14	$83	$136	26,033	$280	$1,664	$2,720
Total	**2,225**	**$23**	**$131**	**$218**	**44,600**	**$460**	**$2,632**	**$4,368**

Source: ICF

The economic impacts that ICF presented above do not include any secondary impacts from other industrial expansions that ACP facilitates. For example, ICF evaluated the impacts related to the incremental gas generation capacity additions in the two states enabled by ACP. This alone could add approximately 1,000 jobs across the two states, 70 percent in NC and 30 percent in VA. More than 95 percent of these positions are estimated to be temporary construction related jobs, with a small fraction of permanent operational jobs. Exhibit 13 shows the detailed breakdown of this impact.

Exhibit 13: Projected Market Area Economic Impact Due to New Natural Gas-Fired Electric Generation Capacity

	Construction Labor		Equipment and Material		Operation and Maintenance		Total	
	Temporary Jobs	Value Added ($ million)	Permanent Jobs	Value Added ($ million)	Permanent Jobs	Value Added ($ million)	Jobs	Value Added ($ million)
Direct	565	$36.9	14	$6.9	21	$2.1	601	$45.9
Indirect	180	$20.5	13	$1.2	3	$0.4	196	$22.1
Induced	223	$23.0	15	$1.5	9	$0.9	247	$25.4
Total	**970**	**$80**	**42**	**$10**	**33**	**$3**	**1,045**	**$93**

Source: ICF

Additional Benefits

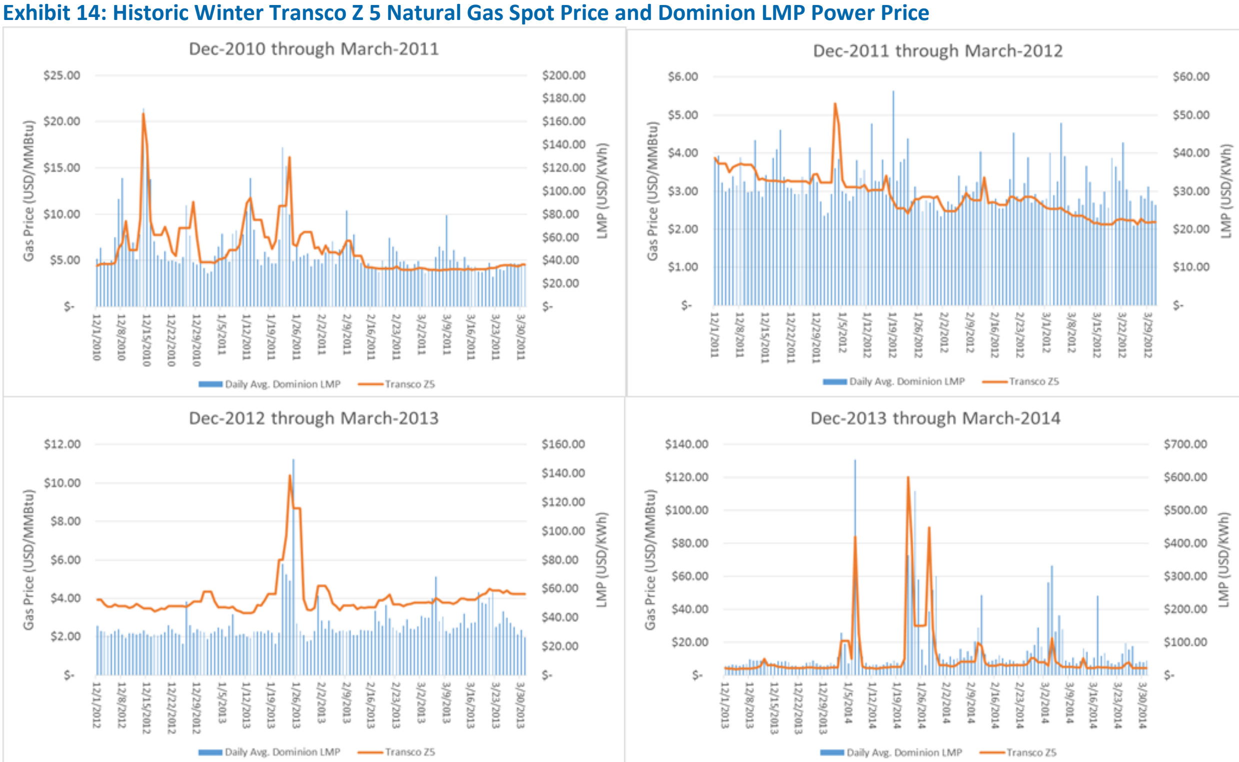
ACP will reduce electric and gas price volatility in the market area

As an incremental supply source, ACP can lower natural gas price volatility in the Virginia and North Carolina markets which, in turn, would reduce the frequency and magnitude of potential power market price spikes. ICF analysis suggests that with ACP, price volatility could be reduced to the relatively moderate levels experienced in the 2011-2012 and 2012-2013 winters, as shown in Exhibit 14, with the

[12] Job-years are the number of jobs multiplied by a number of years.

effects lasting until new pipeline capacity is needed. Lower price volatility can smooth out the month-to-month variation of electric customers' monthly bills, reducing the uncertainty around bill payments and business planning.

Exhibit 14: Historic Winter Transco Z 5 Natural Gas Spot Price and Dominion LMP Power Price



Source: ICF

ACP capacity is likely to reduce the occurrence and size of regional natural gas price spikes in Virginia that will result in corresponding reduction of electricity price spikes, such as those experienced in the winter of 2013-2014. Consumers in Virginia benefit directly from this regional volatility reduction in terms of lower and more predictable electric bills. On the other hand, ACP allows North Carolina consumers' electric bills to be closely linked to gas prices in the Appalachian Basin gas production region, which typically has significantly lower volatility than North Carolina natural gas price.

ACP enhances electric reliability in the region

The firm natural gas supplies transported on ACP promote continued reliability of the electric grid in Virginia and North Carolina, by increasing the predictability of electric plant dispatch and reducing potential costly power supply disruption risks. A North American Electric Reliability Corporation study shows that during the 2013-2014 winter peak load days (January 6 through January 8, 2014), approximately 10,000 MW to 20,000 MW of generation capacity in seven NERC regions (excluding WECC) were not able to dispatch because of a lack of fuel.[13]

For this analysis, ICF estimates that more than 20,000 MW [14] of additional natural gas-fired generation capacity will be installed in Virginia and North Carolina. ACP is critical in providing low-cost, reliable, and

[13] Polar Vortex Review, September 2014, Figure 5.

[14] The capacity expansion plan reflects ICF's opinion regarding regional load growth and capacity needs under the market assumptions used in this analysis.

firm fuel supply to these generators, thereby reducing the possibility of generator outages due to lack of fuel, even under the most adverse weather conditions.

The cost of load shedding can be prohibitively high. For example, PEPCO, a PJM electric utility that serves Maryland and parts of northern Virginia, filed documents with regulators in 2013, estimating that an eight-hour outage for a quarter of its customers could cost approximately $1 billion, as shown in Exhibit 15.

Exhibit 15: Outage Estimates by PEPCO in 2013 Maryland State Filing

Customer Class	8 hrs	¼ # of Customers	Estimated Costs for an 8 Hour Outage affecting ¼ of Customers
Residential	$11	58,774	$623,004
Small C&I	$5,195	65,453	$340,027,569
Large C&I	$69,284	9,350	$647,833,633
		133,557	**$988,484,206**

Source: PEPCO

ACP will support renewable generation in the region

ACP will support increased development of renewable energy capacity in Virginia and North Carolina, such as wind and solar generation. Since these power sources provide power on an intermittent basis (when the wind blows or sun shines), they create a need for additional conventional peaking power plants that can respond quickly to upward or downward changes in electric supply or demand by coming online in minutes.

The majority of quick-start, high ramp power plants coming online today are gas-fired turbine and reciprocating engine technologies. Analyses by the Interstate Natural Gas Association of America (INGAA)[15] indicate that renewable energy sources require quick-start capacity backup equivalent to 10-15% of their rated capacity, if the regional grid does not already contain adequate generation capacity reserves.

Dominion Virginia Power, a Foundation Shipper on ACP, won the lease for 112,800 acres of federal land off of the coast of Virginia, to develop an offshore wind turbine farm, capable of generating up to 2,000 megawatts of electricity -- enough for 700,000 homes[16]. This wind project is likely to need back-up generation --which could be fueled reliably and economically by supplies off of ACP.

Quick-start gas-fired generation is also an important tool to operators for real-time electric grid system regulation. Electric grid operators seek to maintain stable voltage levels, which are impacted by load changes. System regulation requirements are often met with "spinning reserves" or quick-start units that are maintained at the ready. Typically, these are gas-fired plants that can respond to very short-term fluctuations in supply and demand, including deviations in expected output from variable generation sources.

[15]Firming Renewable Electric Power Generators: Opportunities and Challenges for Natural Gas Pipelines", prepared by ICF International for the INGAA Foundation, March 16, 2011. http://www.ingaa.org/File.aspx?id=12761.

[16] http://dom.mediaroom.com/2013-09-04-Dominion-Virginia-Power-Wins-Federal-Offshore-Wind-Auction

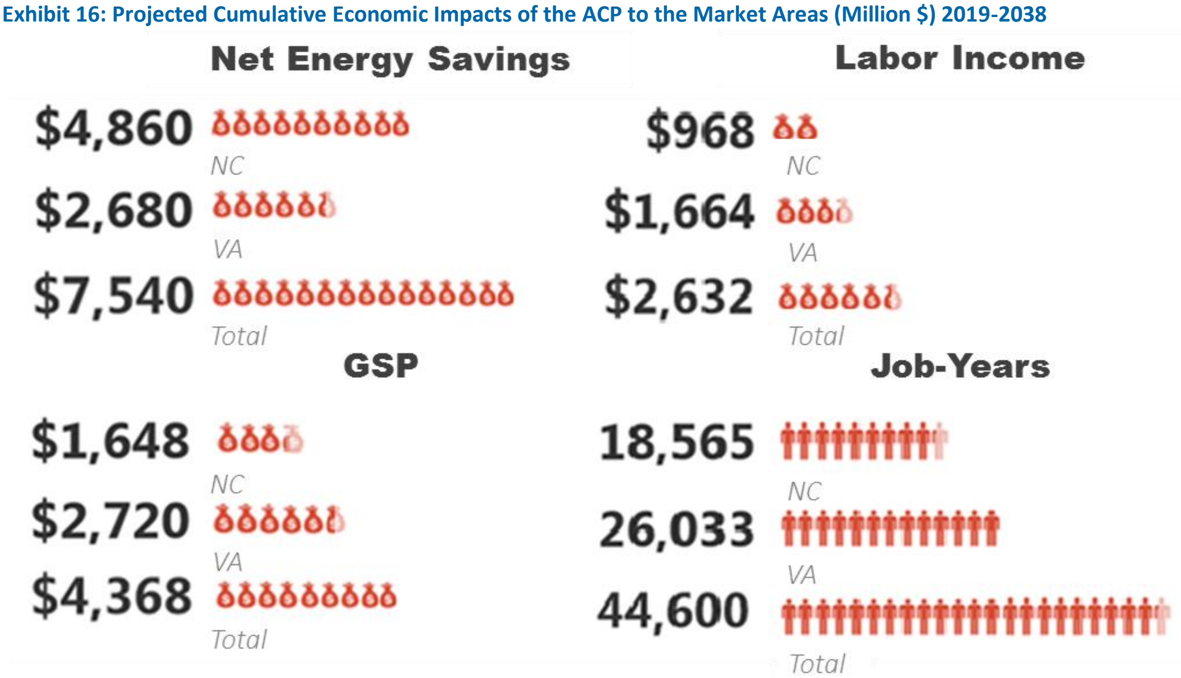
Summary Conclusions

The ACP project is expected to produce significant benefits to energy consumers in Virginia and North Carolina. Based upon reasoned assumptions, ICF found that net energy cost savings to Virginia and North Carolina consumers could average $377 million per year during the study period of 2019-2038. The cost savings largely result from ACP's lowering the costs of natural gas to fuel electric generation -- meaning that the economic benefits of new gas infrastructure will have wide-spread impacts. Each and every energy consumer in Virginia and North Carolina will see the cost savings reflected as a lower natural gas and electric bill.

ICF further finds that ACP benefits the broader state economies. In all, consumer reinvestments of their energy savings in the economy could generate over 2,200 full-time, well-paying jobs and an additional $218 million in GSP per year.

In total, for the 20-year study period, ACP will generate $7.5 billion in energy cost savings, create 45,000 job-years, generate $2.6 billion labor income, and $4.4 billion gross state product in Virginia and North Carolina.

Exhibit 16: Projected Cumulative Economic Impacts of the ACP to the Market Areas (Million $) 2019-2038



Source: ICF

Finally, in addition to the measurable economic impacts, ACP will provide additional benefits to the market area:

- Increase supply security by opening up access to a more diversified portfolio of gas supply choices;
- Increase access to natural gas storage facilities proximate to ACP;
- Reduce consumers' bill volatility by lowering natural gas price volatility in the market region and linking generation cost to low-cost and low-volatility natural gas prices in the Appalachian Basin;
- Enhance regional electricity reliability as power producers will have more avenues to access supply during peak demand or adverse weather which may constrain supply; and

- Support renewable generation as ACP and the associated gas powered generation assets serve to balance the intermittency of wind and solar generation output.

Passion. **Expertise. Results.**